0000096561

Transcript Exhibit(s)

Docket #(s): E-01575A-08-0328

Exhibit # : S2-S13

EXHIBIT

ALL-STATE LEGAL®

S-2

admitted

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS

KRISTIN K. MAYES
GARY PIERCE
PAUL NEWMAN
SANDRA D. KENNEDY
BOB STUMP

IN THE MATTER OF THE APPLICATION OF SULPHUR SPRINGS VALLEY ELECTRIC COOPERATIVE, INC. FOR A HEARING TO DETERMINE THE FAIR VALUE OF ITS PROPERTY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RETURN THEREON, TO APPROVE RATES DESIGNED TO DEVELOP SUCH RETURN AND FOR RELATED APPROVALS.	DOCKET NO. E-01575A-08-0328 **NOTICE OF ERRATA**

Staff of the Arizona Corporation Commission ("Staff") hereby files this Notice of Errata with regard to the direct testimony of Jerry E. Mendl. Mr. Mendl inadvertently omitted the Company's response to data request JEM 14.22 in Exhibit JEM-3 of his direct testimony and through this notice replaces the incomplete Exhibit JEM-3 with a revised and complete Exhibit JEM-3.

As a result of this revision to Exhibit JEM-3, the following changes are necessary to Mr. Mendl's direct testimony:

Page 6, Line 7, insert "page 1," after"JEM-3,"

Page 7, line 4, replace "pages 1 and 2" with "pages 2 and 3"

Staff has attached a revised Exhibit JEM-3 to this Notice of Errata.

RESPECTFULLY SUBMITTED this 19th day of February, 2009.

Wesley Van Cleve

Wesley C. Van Cleve, Attorney
Legal Division
Arizona Corporation Commission
1200 West Washington Street
Phoenix, Arizona 85007
(602) 542-3402

Original and thirteen (13) copies of the foregoing were filed this 19th day of February, 2009 with:

Docket Control
Arizona Corporation Commission
1200 West Washington Street
Phoenix, Arizona 85007

Copies of the foregoing mailed this 19th day of February, 2009 to:

Bradley S. Carroll
SNELL & WILMER, L.L.P.
One Arizona Center
400 East Van Buren
Phoenix, Arizona 85004-2202

Roseann Osorio

EXHIBIT A

**RESPONSE OF SSVEC
TO ARIZONA CORPORATION COMMISSION
STAFF'S FOURTEENTH SET OF DATA REQUESTS
DOCKET NO. E-01575A-08-0328**

December 15, 2008

JM 14.29 **Please explain in detail whether and how SSVEC's organizational structure related to purchase power acquisition changed given the changed responsibilities in going from the full requirements contract with AEPCO to a partial requirements contract.**

Response: SSVEC has not made changes to its organizational structure as a result of the conversion to partial requirements service. Some additional responsibilities are carried by existing positions however. The CEO retains overall management and decision-making authority for power supply decisions. The Chief Financial and Administrative Officer oversees the day-to-day power procurement, scheduling, and sales activities. SSVEC manages the remaining workload through contract services with WAPA as its scheduling and GDS Associates, Inc. as its power supply consultant.

Prepared by: David M. Brian, P.E.
GDS Associates, Inc.
1850 Parkway Place, Suite 800
Marietta, Georgia 30067

**RESPONSE OF SSVEC
TO ARIZONA CORPORATION COMMISSION
STAFF'S FOURTEENTH SET OF DATA REQUESTS
DOCKET NO. E-01575A-08-0328**

December 15, 2008

JM 14.22 **Please describe the organizational structure for implementation and oversight of SSVEC's purchase power procurement method, including:**

a) **Identify who has responsibility for determining the volumes of purchase power to be procured.**
b) **Identify who has responsibility for securing bids.**
c) **Identify who has responsibility for evaluating offers.**
d) **Identify who has responsibility for deciding to accept or reject offers.**
e) **Identify the levels of management approval required to enter into a purchase power contract.**
f) **Identify who has responsibility for SSVEC's price risk management activities.**
g) **Identify who has ultimate authority for decisions regarding purchase power procurement.**
h) **How does SSVEC monitor the results of its purchase power procurement process, including how it determines whether situational deviations from its policies/procedures are needed?**

Response:

a) The SSVEC Chief Financial and Administrative Officer (CFO) gathers information and recommendations from both WAPA and SSVEC consultants, and collectively the group decides what products to procure with the final decision being made by the CFO. SSVEC's Chief Executive Officer (CEO) is consulted in advance of all purchase decisions.

b) WAPA requests bids for products on behalf of SSVEC.

c) The CFO gathers suggestions from both WAPA and SSVEC consultants, and collectively the group decides what products to procure with the final decision being made by the CFO.

d) The CFO gathers information and provides recommendations on offers to the CEO.

e) The CEO approves all major purchases.

f) The CFO is responsible for price risk management.

g) The SSVEC Board of Directors approves company budgets which include power supply. The CEO approves expenditures approved in the budget including power supply agreement. The CFO works with WAPA and SSVEC consultants on day to day operational matters.

h) The Board of Directors and the CEO are provided with monthly updates on the power supply activities. WAPA monitors the power markets on a daily basis for potential purchases that could be beneficial to SSVEC.

**RESPONSE OF SSVEC
TO ARIZONA CORPORATION COMMISSION
STAFF'S FOURTEENTH SET OF DATA REQUESTS
DOCKET NO. E-01575A-08-0328**

December 15, 2008

Prepared by: Kirby Chapman
Sulphur Springs Valley Electric Cooperative
Chief Financial and Administrative Officer
311 E. Wilcox Drive
Sierra Vista, AZ 85635

EXHIBIT
S-3
admitted

BEFORE THE ARIZONA CORPORATION COMMISSION

KRISTIN K. MAYES
Chairman
GARY PIERCE
Commissioner
PAUL NEWMAN
Commissioner
SANDRA D. KENNEDY
Commissioner
BOB STUMP
Commissioner

IN THE MATTER OF THE APPLICATION OF SULPHUR SPRINGS VALLEY ELECTRIC COOPERATIVE, INC. FOR A HEARING TO DETERMINE THE FAIR VALUE OF ITS PROPERTY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RETURN THEREON, TO APPROVE RATES DESIGNED, TO DEVELOP SUCH RETURN AND FOR RELATED APPROVALS

DOCKET NO. E-01575A-08-0328

SURREBUTTAL

TESTIMONY

OF

JERRY E. MENDL

ON BEHALF OF

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

APRIL 3, 2009

TABLE OF CONTENTS

EXECUTIVE SUMMARY
SULPHUR SPRINGS VALLEY ELECTRIC COOPERATIVE, INC.
DOCKET NO. E-01575A-08-0328

This Surrebuttal Testimony supports the conclusions and recommendations from my Direct Testimony. In addition, I am recommending that Staff conduct a prudence review in the next rate case or within three years, whichever comes first.

INTRODUCTION

Q. Are you the same Jerry E. Mendl who filed Direct Testimony in this docket on February 9, 2009?

A. Yes.

Q. What is the purpose of your Surrebuttal Testimony today?

A. The purpose of my Surrebuttal Testimony is to respond to the Rebuttal Testimony submitted by Mr. David M. Brian. Mr. Brian commented regarding three topics that I discussed in my Direct Testimony, namely institutional factors, purchase power prices relative to market prices, and alternative approaches. I will address the three principal matters Mr. Brian raised on pages 4-5 of his Rebuttal Testimony. Specifically I will address Mr. Brian's:

- Assertion that Sulphur Springs Valley Electric Cooperative, Inc. ("SSVEC") has adequate power procurement procedures which are and will be effective.
- Assertion that I have presented an unfair analysis of SSVEC's purchasing activities and third party purchases in particular.
- Assertion that my consideration of alternative approaches is neither complete not relevant, at least as it relates to Arizona Electric Power Cooperative, Inc. ("AEPCO") all requirements service.

Q. Mr. Brian testifies on page 3 that your "conclusions and recommendations are based in large part on an incomplete understanding of SSVEC's history and power supply activities." He goes on to state that his testimony will clear up many of the issues that you raised. Has Mr. Brian's testimony, in conjunction with the materials and analyses you have previously evaluated, caused you to modify your conclusions and recommendations as expressed in your Direct Testimony?

A. No. While Mr. Brian's testimony in some instances provided additional information, it mostly provided opinion and argument. Ultimately, it did not substantially change my understanding of SSVEC's history and power supply activities, and it did not cause me to materially modify my conclusions and recommendations.

Q. Do you have any additional recommendations?

A. Yes. I recommend that the Commission Staff conduct a prudence review of SSVEC's purchased power procurement processes in the next rate case or within three years, whichever comes first. This would give SSVEC time to fully develop and implement its power purchase procurement process. It would also ensure that the issue would be revisited in a reasonable time frame to ensure that SSVEC's customers are not paying excessive prices for electric energy.

INSTITUTIONAL FACTORS

Adequacy of power procurement procedures

Q. What is your understanding of Mr. Brian's testimony regarding the adequacy of SSVEC's power procurement procedures?

A. Mr. Brian asserts that SSVEC's power procurement procedures are and will continue to be adequate, and that the recommendations I made to improve SSVEC's purchase power procurement procedures are not necessary. He makes four arguments in support of his assertions:

1. SSVEC has written policies in place.
2. SSVEC follows adequate procedures and policies to ensure prudent and reasonable power procurement, but they are unwritten and not formalized.
3. Written or formalized procedures would have no benefit, and could have led to worse results.
4. SSVEC is too small to require well documented written procedures.

Q. Do SSVEC's written policies eliminate the concerns you raised in your Direct Testimony regarding the lack of purchase power procurement procedures?

A. No. To put it into perspective, the SSVEC Board adopted policies setting forth the general responsibilities of the Chief Executive Officer and Executive Vice President in 1986, with periodic amendments. The policy established that the CEO also had the job title of Executive Vice President, and that the Executive Vice President had the authority to enter into purchased power agreements with terms of one year or less, or longer than one year with prior Board approval of contracts of similar form. In 1989, with periodic amendments, the SSVEC Board authorized the CEO to approve the purchase of and payment for items, and to delegate to subordinates the purchase of items within certain limits. The CEO can delegate authority to the Chief Financial Officer to purchase approved budget items up to $50,000. The CEO is authorized to purchase and pay for all purchased power transactions. These policies help clarify the roles and responsibilities of the CEO and CFO, and SSVEC should be given credit for that.

However, clarifying the spending authorities at some general level is only a small part of the power procurement procedures that I found lacking.

The mere existence of the Board policies does not necessarily mean that they are regularly and vigorously implemented. To that end, though Mr. Brian appears to suggest that I may have come to a different conclusion had I been aware of the policies. However, he does not acknowledge that SSVEC procurement personnel were either unaware of the policies or did not believe them to be relevant. I had requested such information in data requests JM 14.18, 14.19 and 14.20. See Exhibit JEM-4. The response to JM 14.18 indicated that SSVEC did not have "a formal power procurement plan in place." In data request JM 14.19 I asked whether "a manual, guideline, policy, risk-management policy, or any other written documents to guide its electric power procurement personnel" existed, and requested copies. SSVEC did not indicate the existence of any such documents, and did not provide the SSVEC Board policies in response to the request. This raises doubt about how the Board policies are implemented, or whether SSVEC personnel even consider them in their day-to-day operations.

In summary, the SSVEC Board policies clarify only a small part of the overall issue that I raised, and still leave the question as to whether, and how they are implemented. SSVEC did not initially recognize them as relevant to their power procurement procedures. The existence of the SSVEC Board policies does not materially alter my previous recommendations.

Q. Do Mr. Brian's assertions that SSVEC has an adequate power procurement process alleviate your concerns about the lack of a documented and enforceable procurement process?

A. No. Mr. Brian testifies (page 13) that the "process used by SSVEC to procure power in 2008 was consistent with any formal written procedures it could have developed, had it done so." He continues, "While the process is not heavily documented or regimented in the form of procedures, it has worked well, and continues to work well."

I have two main problems with this assertion. First, he implies that there is a reasonable, well conceived procurement process in place, but that it is simply not well documented. I have no reliable evidence that SSVEC is following a reasonable, well conceived, but informal and undocumented procurement process. In fact, I asked whether SSVEC had any informal or unwritten guidelines or strategies for purchasing electricity and for a description of them in data request JM 14.20. See Exhibit JEM-4. I received the answer prior to drafting my Direct Testimony, and concluded that SSVEC did not have concrete well defined procedures. Rather, SSVEC's process appears to be *ad hoc*, and Mr. Brian's testimony only reinforces that appearance. I do not believe that an *ad hoc* process will be as effective in dealing with changing conditions and volatile markets as an organized process that has been designed to address contingencies as they occur.

Second, Mr. Brian asserts that the process has worked well, and continues to work well. There is no evidence that it has worked well in terms of keeping down the cost of power for SSVEC's customers. SSVEC converted to partial requirements service in order to avail itself of market opportunities to secure power at costs below those charged by AEPCO. My analysis of SSVEC's power cost through October 2008 showed that the opportunities that SSVEC availed itself of were substantially more costly than the cost of power from AEPCO. They also were substantially more costly than spot market prices. This is not evidence that SSVEC's process has worked well.

Q. Do you agree with Mr. Brian's opinion that the written or formalized procedures would have no benefit?

A. No. Having written or formalized procedures adds discipline to the purchasing strategy, as well as accountability. It also provides guidance to the procurement personnel, and a benchmark against which to assess performance and make improvements. I addressed those points in my Direct Testimony, and with due consideration to the assertions of Mr. Brian to the contrary, I have seen nothing in Mr. Brian's rebuttal that would cause me to modify my conclusions and recommendations regarding the need for and appropriateness of a well documented and formalized procurement process.

Q. Do you agree with Mr. Brian's opinion that the written or formalized procedures may have led to worse results?

A. No. Mr. Brian appears to base that opinion on a concept of the procedures as being inflexible and forcing SSVEC to purchase power when prices were high. First of all, well crafted procedures will retain some flexibility while providing discipline and accountability. Established procedures will increase the likelihood of a rational and reasoned response to changing circumstances because the responsible personnel are operating within an existing framework rather than in a panic crisis mode. Within the framework, well crafted procedures will also provide guidance on how to address contingency conditions and how to monitor performance to modify the procedures. In other words, well crafted procedures give advance thought to situations and circumstances that may occur, and thus prepare the responsible personnel for reasonably dealing with them if and when they do occur.

Second, Mr. Brian assumes that written or formalized procurement procedures could have resulted in a requirement to purchase more power through forward purchase arrangements at a time when prices were high rather than to purchase more electricity on the spot market. This is an extreme assumption. Mr. Brian assumes that the formalized procurement procedures would have required SSVEC to lock in all of its power needs when prices were high within weeks before deliveries were to start, and thus not get the benefit from reduced spot market prices. In reality, the procurement procedures may have secured some of the power before electric forward prices rose. The procurement procedure may have also intentionally left an open position subject to specific conditions rather than making that decision on an *ad hoc* basis.

Q. Does the informal procurement process described by Mr. Brian instill confidence that SSVEC's power procurement process reasonable and appropriate?

A. No. It is very *ad hoc* and reactionary in nature, and is not as likely to give consistently good results over time.

By way of background, SSVEC's actual approach identified a need to purchase power for summer 2008, but as prices were rising, put off locking into power purchases until days before delivery began in May. At that point, SSVEC locked in one third of its remaining power need for May. For the June – August period, SSVEC locked up one third of its remaining power need in early June. Mr. Brian indicates (page 18) that "SSVEC refrained from purchasing more forward power for the summer period as wholesale power prices for the summer rose dramatically during the spring months." He goes on to laud SSVEC for having made the good decision to limit its forward purchases because spot market prices turned out to be much lower later in the summer.

This illustrates the *ad hoc* nature of SSVEC's power procurement method. SSVEC knew long before the summer of 2008 that it would need additional power supply resources. Rather than purchase at least some of the power in an orderly and organized fashion in advance, SSVEC waited until days before the power delivery was to begin to purchase part of its needs, and left the rest to supply from the spot market. Over this period, prices were generally rising. Rather than making an organized purchase under a conscious decision, it appears that SSVEC waited to the last minute and panicked – it's "process" left it with no option to buy early or buy over time.

The *ad hoc* nature of SSVEC's power procurement method is further illustrated by Mr. Brian on page 21, where he explains why SSVEC entered into the forward contracts for about one third of its remaining summer power requirement in May and June 2008. He states, "SSVEC was concerned that prices were going to continue to climb, and it was looking to hedge its exposure to the spot market."

In other words, SSVEC knew it needed additional power supplies for the summer. SSVEC considered forward purchases, but took no action (relying on the spot market by default) while prices rose. At least until May and June, after the forward prices and spot market prices had risen, when SSVEC purchased now expensive forward power supplies to hedge exposure to the spot market. As it turned out, deviating at the last moment from SSVEC's *de facto* policy of relying on the spot market by buying some forward supplies was expensive because the spot prices declined. Had spot market prices stayed high or continued to climb, buying forward supplies may have appeared less expensive, especially if done earlier before the prices rose. But then that raises the question of why SSVEC didn't purchase more power on forward supply contracts, and why not earlier?

Q. Is it fair to judge the prudence of SSVEC's power purchases measured against 20-20 hindsight?

A. No. No one knows the future. What is needed is to have a procedure in place to guide decisions in an uncertain future. SSVEC's current informal "procedure" gives no guidance. What were SSVEC's criteria for choosing not to enter into forward purchases earlier (*de facto* riding the spot market)? What were SSVEC's criteria for limiting exposure to the spot market that prompted it to enter into what became expensive forward purchase contracts? What were SSVEC's criteria for choosing a third of its remaining requirements on a forward basis? If it had planned to ladder its remaining requirements in three tranches, why did it not have a disciplined purchase strategy to secure those over time, rather than to purchase the first tranche days before delivery was to begin?

Without a formalized and documented written power procurement procedure, any review invites 20-20 hindsight. One can always look at the results and identify how they could have been better or worse if different decisions had been made or if circumstances had played out differently. But that is not particularly useful, either to determine prudence and reasonableness or to identify changes and improvements to the power procurement process. The benchmarks and guidance provided by a well conceived and written procedure not only counter the temptation to rely exclusively on 20-20 hindsight, but also provide opportunities to get consistent and reproducible good results.

By establishing the procedures, you define what a reasonable person would do. Prudence, and job performance, becomes a question of how well the responsible personnel executed the procedures in light of the circumstances during the review period.

Q. Mr. Brian distinguishes smaller utilities in his testimony, arguing that written procedures are not appropriate for smaller utilities. Do you agree?

A. No. While I do recognize that smaller utilities generally will have fewer resources and fewer personnel to fulfill its responsibilities, and may have fewer options available to it (e.g., it is not likely that SSVEC would build a nuclear power plant to serve its loads), that does not translate into the conclusion that written procedures are not appropriate for smaller utilities. To the contrary, the responsibility to reliably serve customers at reasonable cost is common to both large and small utilities. The decisions regarding power supply, including whether, when and how much power to purchase are made by responsible personnel in larger utilities and smaller utilities alike. SSVEC entered that realm when it chose to become a partial requirements customer and took on the responsibility of securing its own power supplies.

Being a smaller utility does not negate the importance or the consequence of the decisions that the utility must make to secure power supplies. Although the total dollar cost may be less than a corresponding decision for a large utility, the cost per customer or cost per kWh is probably similar. Therefore, for all the reasons I have previously mentioned, having written and documented procedures is important for small utilities as well as large utilities.

Q. If a small utility contracts out some of its power procurement activities, to WAPA and GDS, for example, does that eliminate the need for written procedures?

A. No. The decisions are ultimately still made by the responsible utility personnel, and thus the written procedures should still be in place to guide those decisions. The written procedures would guide the key utility personnel, but also communicate the authorities and objectives to the contract personnel.

Q. Mr. Brian asserts that the procedures you are recommending are not commonplace, and alleges that you have not seen the types of procedures that you are suggesting used in practice (page 14). What is your reaction?

A. Perhaps Mr. Brian has not seen these types of procedures, but I have. Mr. Brian states that I could not provide a single instance where I had seen these types of procedures used for power procurement. I provided three examples in the Southwest in response to SSVEC 2.1 which he attached as Exhibit DMB-5. He dismisses those as natural gas related, which is simply not true. Nevada Power Company and Sierra Pacific Power Company procedures apply to electric power resources, including purchased power. In those utilities, the procurement procedures and strategies are documented in the integrated resource plans ("IRP") and energy supply plans ("ESP") filed with the Public Utilities Commission. In addition, these utilities have written manuals and procedures to provide guidance and performance benchmarks. I am currently engaged in a docket with these two utilities addressing resource optimization strategies, which includes the purchase and sale of electric power to potential buyers such as SSVEC.

Mr. Brian also apparently did not consider my rather detailed response to SSVEC 3.1 when he determined that my experience was not relevant to electric power purchases. In my response to SSVEC 3.1, I provided two work assignments within the past ten years, as requested by SSVEC, where the subject matter involved power supply planning for an electric cooperative. I also provided thirteen work assignments within the past ten years grouped by client and utility involving power supply planning for an electric utility other than an electric cooperative. These groupings sometimes included multiple dockets. At the top of that list were Nevada Power and Sierra Pacific Power, which described the resource optimization strategy, electric power sales and electric resource mix among the issues. I also attached copies of about 25 pieces of testimony that I had given, as requested by SSVEC, that were pertinent to electric power supply planning. This included the testimony relative to resource optimization strategy and electric power planning and purchases referenced in my response to SSVEC 2.1.

Finally, Mr. Brian asserts that I have not worked with smaller utilities or on projects dealing with power supply matters for an electric power cooperative (page 15). I worked on power supply matters related to two electric power cooperatives as indicated in my response to SSVEC 3.1. Although it occurred more than ten years ago, and was thus not included in my response to SSVEC 3.1, I have worked for the American Public Power Association regarding power supply resources. I have also worked on projects involving power supplies for Wisconsin Public Power, Inc., Western Wisconsin Municipal Power Group, the Marshfield municipal utility, the Menasha municipal utility, Dairyland Power Cooperative, and several other small utilities. It would be illogical to dismiss my experience as irrelevant to small utilities or public (not-for-profit) power.

Q. Has Mr. Brian's testimony regarding SSVEC's organizational structure and power procurement procedures caused you to modify your recommendations and conclusions?

A. No, I have not modified my recommendations pertaining to organizational structure and power procurement procedures based on my review of Mr. Brian's testimony.

However, Mr. Brian's testimony has caused me to modify my conclusions. My initial review of SSVEC's organizational structure and power procurement procedures led me to conclude that some improvements were required, but that SSVEC was in transition and was in the process of developing, implementing and refining its power procurement procedures. I believed that SSVEC was open to upgrading and documenting its power procurement procedures, and would be making a good faith effort to do so as it gained more experience with its new responsibilities.

Mr. Brian's testimony suggests otherwise, namely his belief that formalized, written and documented power procurement procedures are inappropriate. If Mr. Brian has his way, I now conclude that SSVEC will not make the improvements to its organizational structure and power procurement procedures.

Therefore, I am now augmenting my recommendations to suggest that the Commission Staff conduct a prudence review of SSVEC's purchased power procurement activities in the next rate case, or within three years, whichever comes first.

PRICES PAID BY SSSVEC FOR PURCHASED POWER

Q. Mr. Brian asserts that your analysis of the prices paid for purchased power is flawed because you compared on-peak pricing to off-peak pricing in your comparison. Please comment.

A. Mr. Brian makes that assertion, and then goes on to state that "the APS and PNM purchases are on-peak purchases six days a week." (Page 19, line 21) Mr. Brian is wrong. The APS and PNM purchases are for 16 hours per day, seven days per week including NERC holidays. As such, SSVEC purchased power from APS and PNM during off-peak hours as well as on peak-hours.

At least 16 hours per week, SSVEC was purchasing power during the off-peak period at on-peak prices. In addition, SSVEC also purchased power during the off-peak NERC holidays at on-peak prices on Monday, May 26, 2008 (Memorial Day) and Friday, July 4, 2008 (Independence Day).

It is disingenuous of Mr. Brian to criticize my analysis, which was based on using balancing transactions prices as a proxy for market prices. I requested market price information in data requests to SSVEC. SSVEC responded that it did not maintain any such data base, and did not have access to any such data base.

Q. Mr. Brian indicates that correcting your "mistake" by only comparing the third party contracts to on-peak prices yields significantly different results. Do you agree?

A. No. First, his analysis ignores that fact that SSVEC purchases some of the power from APS and PNM during the off-peak period.

However, even making the assumption that Mr. Brian makes and ignoring the off-peak purchases, he points out that in June, of the 138 balancing transactions made during the on-peak period, 35 were at prices greater than what SSVEC paid under the APS contract. Stated differently, the prices SSVEC paid were above the market in 75 percent of the transactions in June.

Furthermore, he suggested that similar results would occur in the other months that I analyzed. In May, 20 of the 106 on-peak balancing transactions were at prices greater than what SSVEC paid under the third party contract. Thus the prices SSVEC paid were above the market in 81 percent of the transactions in May.

In July, 19 of the 103 on-peak balancing transactions were at prices greater than what SSVEC paid under the third party contract. Thus the prices SSVEC paid were above the market in 82 percent of the transactions in July.

In August, 1 of the 97 on-peak balancing transactions were at prices greater than what SSVEC paid under the third party contract. Thus the prices SSVEC paid were above the market in 99 percent of the transactions in August.

For the four-month period in which SSVEC made third party purchases, the on-peak market prices, as measured by the on-peak balancing transactions, were greater than the third party purchase prices on 77 of 444 occasions. For the summer 2008 season, SSVEC third party purchased power prices were above the on-peak market price in 83 percent of the on-peak balancing transactions. By comparison, my direct testimony, which included both on-peak and off-peak balancing transactions, indicated that SSVEC third party purchased power prices were above the price of all balancing power transactions in 90 percent of the balancing transactions. While the numbers change given the assumption that Mr. Brian made, it is hardly a vindication of SSVEC's power purchase results.

Q. Do you agree with Mr. Brian that the fair way to evaluate the reasonableness of the pricing is to review the information that the utility had before it at the time the decision was made? (Page 21, line 12)

A. It depends on the purpose of the evaluation. I would agree that it is a typical standard in prudence review. However, it is not only a question of what information a utility had, but what it should have had and how it processed that information.

In my analysis, I concluded that SSVEC does not have a documented process by which to secure and utilize information which would lead to an orderly and systematic method for securing power cost effectively. I also concluded that SSVEC does not collect the data necessary to monitor and evaluate its performance, and to modify its procurement process to improve its performance. Both of these are factors affecting a prudence determination that go beyond simply reviewing what information a utility had at the time it made a decision.

Q. Why did you develop an analysis comparing third party purchase prices to spot market conditions?

A. First, spot market conditions are a benchmark against which to assess the performance of SSVEC's approach to power procurement. In effect, buying power from the market is an option that exists. If buying from the market would consistently yield lower prices than whatever approach SSVEC was using to procure power, it would suggest to me that SSVEC should reassess its purchased power procurement practices.

Second, I also compared third party purchase prices to power supplied under the AEPCO partial requirements contract. One reason is that AEPCO represents a competing source of power supply. Another reason for doing that analysis is that SSVEC was publicly stating that AEPCO costs were the reason for high power prices charged to SSVEC customers in early summer 2008. My analysis found that SSVEC customers were experiencing rate increases resulting from third party purchases and higher market prices, not AEPCO cost increases. Costs paid to AEPCO were essentially constant, both in total dollars and average cost per kWh purchased. Balancing power (spot market) and third party power prices were significantly higher.

ALTERNATIVE APPROACHES

Q. Do you agree with Mr. Brian that SSVEC already utilizes laddered purchasing strategies? (Page 28, line 13)

A. No. SSVEC may have considered laddering, and may have planned to procure electricity on a laddered approach in 2008, but it did not do so. Mr. Brian stated that SSVEC planned to purchase 75 MWs in three staggered 25 MW increments (page 28, line 20). I would agree that would have constituted laddering, if done over a reasonable period of time. Mr. Brian goes on to state that the APS and PNM purchases were 25 megawatt purchases reflecting the first layer of this plan, and that it was later decided not to do more than the first layer. Thus, Mr. Brian admits that SSVEC did not actually ladder its purchases in 2008, although they may have considered doing so.

Furthermore, Mr. Brian states that the APS and PNM purchases were the first layer of the laddered approach. Yet, SSVEC entered into those contracts literally days before delivery started. Since they were the first layer, it would have been impossible to buy the other two layers in advance with the purchases staggered over time.

Q. Despite higher costs in 2008, Mr. Brian states that SSVEC believes the partial requirement status with AEPCO is better because SSVEC has independent control to establish its own strategy for part of its power supply requirements (page 30, line 1). Do you agree?

A. Yes, SSVEC could reduce its power supply costs through independently managing part of its power procurement, but <u>only if</u> SSVEC takes the appropriate steps. Thus far, I have not seen evidence that SSVEC has taken the organizational and procedural steps to help ensure independent power procurement success. The process laid out so far is *ad hoc* in nature, and is not well documented. My analysis of the costs incurred in 2008 indicates that SSVEC power procurement led to higher rather than lower costs.

While the partial requirements service from AEPCO offers SSVEC the potential to reduce its costs, those results are not at all assured at this time. I believe it is reasonable to give

SSVEC the opportunity to fully implement and document a purchase power procurement process, and revisit the prudence of that process within three years.

Q. Does this conclude your Surrebuttal Testimony?

A. Yes it does.

EXHIBIT

S-4

admitted

BEFORE THE ARIZONA CORPORATION COMMISSION

KRISTIN K. MAYES
Chairman
GARY PIERCE
Commissioner
PAUL NEWMAN
Commissioner
SANDRA D. KENNEDY
Commissioner
BOB STUMP
Commissioner

IN THE MATTER OF THE APPLICATION OF SULPHUR SPRINGS VALLEY ELECTRIC COOPERATIVE, INC. FOR A HEARING TO DETERMINE THE FAIR VALUE OF ITS PROPERTY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RETURN THEREON, TO APPROVE RATES DESIGNED TO DEVELOP SUCH RETURN AND FOR RELATED APPROVALS.	DOCKET NO. E-01575A-08-0328

REDACTED

DIRECT

TESTIMONY

OF

JERRY E. MENDL

ON BEHALF OF

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

FEBRUARY 9, 2009

TABLE OF CONTENTS

EXHIBITS

EXECUTIVE SUMMARY
SULPHUR SPRINGS VALLEY ELECTRIC COOPERATIVE, INC.
DOCKET NO. E-01575A-08-0328

The Arizona Corporation Commission ("ACC") secured the services of MSB Energy Associates, Inc. ("MSB"), to evaluate Sulphur Springs Valley Electric Cooperative, Inc. ("SSVEC") power purchases made since January 1, 2008. The purpose of the review is:

- To evaluate SSVEC's procurement process for power purchases from the spot market and suppliers other than the partial requirements service from Arizona Electric Power Cooperative ("AEPCO").
- To identify deficiencies in SSVEC's power procurement process and make recommendations for improvements.
- To determine whether the costs incurred for purchase power since January 1, 2008 are indicative of SSVEC's future purchase power.

In conducting its analysis, MSB analyzed institutional factors (the existence of organizational structure and procurement procedures), execution (of the procurement procedures), prices (paid relative to market), and alternatives (that SSVEC might use to reduce costs).

Conclusions:
MSB concluded that the prices SSVEC paid in 2008 are not likely to be representative of purchase power prices it will incur in 2009 and beyond. MSB also concluded that the negotiated prices SSVEC paid for power from third party suppliers were significantly higher than those paid under the AEPCO contract or the spot market. MSB would expect future prices for third party power to be relatively lower compared to market prices. This is because MSB would expect that revised procedures and organization, which were in transition in 2008 as a result of conversion from full to partial requirements service, would result in improved performance.

Institutional Factors:
Are SSVEC's organization structure and power procurement procedures appropriate? No.

I recommend that the Commission direct SSVEC to:

a. Define and document the responsibilities and limits of authority to make decisions about power supplies and purchases;
b. Establish and document a clearly enforceable set of checks and balances on the authority of personnel involved in power supply planning and power procurement;
c. Develop written procedures for power supply planning and power procurement and formally approve them;
d. Formalize and document the communication of power supply planning and procurement strategies and procedures to the responsible personnel;
e. Develop, document and implement a power procurement monitoring mechanism; and
f. Develop and implement a mechanism to review and update power procurement procedures.

Execution:
Did SSVEC appropriately follow its power procurement procedures? No, because SSVEC has not adopted written formal power procurement procedures, I could not make the determination that SSVEC appropriately followed its procedures. SSVEC also has not developed mechanisms to monitor its performance and adjust its procedures as warranted.

I recommend that the Commission require SSVEC to:

a. Develop and formally adopt written power procurement policies/procedures;
b. Develop a mechanism to monitor changing market conditions and make deviations from the adopted policies/procedures when appropriate (temporary changes in conditions/circumstances); and
c. Develop a mechanism to update the written policies/procedures when permanent changes in conditions/circumstances warrant.

Prices:
Were SSVEC's power purchases made at prices favorable compared to regional market prices? No. On average, SSVEC's purchases from third party suppliers were substantially more expensive than the spot market, as measured by WAPA balancing power transactions. Ninety percent of the WAPA balancing transactions occurred at prices less than the negotiated prices that SSVEC paid for third party purchases. Both third party and average balancing power transactions were at prices substantially above AEPCO full or partial requirements service supplies in the January 1-October 31 2008 time period.

I recommend that the Commission:

a. Find that the third party power supplies secured by SSVEC, in lieu of remaining a full service customer of AEPCO, were at substantially higher prices than power supplies from AEPCO.
b. In an effort to reduce the relative cost of third party power supplies, direct SSVEC to formalize and upgrade its power planning process to ensure it appropriately considers the full spectrum of resources available to it.
c. In an effort to reduce the relative cost of third party power supplies, direct SSVEC to formalize and upgrade its power procurement process to ensure it identifies and appropriately implements available resources and holds SSVEC accountable (e.g., timing of purchases and RFPs, optimize purchases and sales).
d. Direct SSVEC to verify and document that WAPA balancing transactions are conducted at market prices and that they are done in a manner consistent with SSVEC's interests.

Alternative approaches:
Are there alternative approaches that would be more appropriate to ensure that SSVEC's purchased power costs are prudent and reasonable? Yes.

I recommend that SSVEC:

a. Upgrade and document its power planning and procurement processes as indicated in other parts of my testimony.

b. Assess electricity market conditions and adapt power procurement procedures and alternatives to changes in markets. If the electricity market is not sufficiently vibrant and liquid, the market will not be a reliable source of inexpensive power and will provide little opportunity to improve upon the AEPCO full requirements service.
c. Continue to evaluate physical hedges to market prices, including long term purchased power options, long term joint generation ownership options, and also the development of a local peaking generation facility.
d. Evaluate demand response programs and energy efficiency programs to reduce market exposure.
e. Evaluate financial hedges and laddered purchasing strategies to reduce market price volatility.
f. Evaluate returning to full requirements service if SSVEC cannot demonstrate an actual benefit from utilizing electricity markets to supplement partial requirements services from AEPCO.

INTRODUCTION

Q. Please state your name and business address.

A. My name is Jerry E. Mendl. I am the President of MSB Energy Associates, Inc. ("MSB"). My business address is MSB Energy Associates, Inc., 1800 Parmenter Street, Suite 204, Middleton, Wisconsin 53562.

Q Does Exhibit JEM-1 summarize your qualifications?

A. Yes.

Q What is the purpose of your testimony?

A. I am appearing on behalf of the Staff of the Arizona Corporation Commission - Utilities Division to address the prudence of Sulphur Springs Valley Electric Cooperative, Inc.'s ("SSVEC " or "the Cooperative") electric power procurement practices since January 1, 2008, the date that SSVEC converted from full requirements to partial requirements service from Arizona Electric Power Cooperative, Inc. ("AEPCO"). Since SSVEC ended its full requirements contract for power supplies from AEPCO on December 31, 2007, its 2008 electric power purchases under the partial requirements contract with AEPCO and from other electric power suppliers represent a known change from the test year.

Q. How did you conduct your analysis?

A. I assessed the reasonableness of SSVEC's electric power purchases in 2008 and considered the extent to which the 2008 experience could be indicative of SSVEC's electric power purchases in the future. My analysis is intended to address four major elements:

I. Are SSVEC's organization and power procurement procedures appropriate?

II. Did SSVEC appropriately follow its power procurement procedures?

III. Were SSVEC's power purchases made at prices favorable compared to regional market prices?

IV. Are there alternative approaches that would be more appropriate to ensure that SSVEC's purchased power costs are prudent and reasonable?

Q. What are your principal findings?

A. In my review of SSVEC's electric power procurement practices, I concluded:

1. That purchased power prices SSVEC incurred in January 1 – October 31 2008 are not likely to be representative of purchase power prices in 2009 and beyond.
2. That SSVEC's organizational structure and power planning and procurement procedures should be upgraded and documented.
3. That SSVEC should develop mechanisms to assess its power procurement performance and to make improvements to its organizational structure and power procurement procedures when warranted.
4. SSVEC's negotiated third party power supply prices were significantly higher than spot market prices and the AEPCO full or partial requirements service.
5. SSVEC should assess other approaches to assure reasonable purchase power costs, including physical hedges, financial hedges, demand response and energy efficiency programs.

INSTITUTIONAL FACTORS

Are SSVEC's organization and power procurement procedures appropriate?

Q. What elements should the Commission consider in determining whether SSVEC is appropriately organized to plan for and procure its power supplies?

A. An appropriate structure should clearly define who has the authority to make decisions about power supplies and purchases. These decisions should include integrated resource planning decisions to determine whether SSVEC should build or purchase power plants, initiate demand response programs, initiate energy efficiency programs, purchase power from designated power plants, purchase power from the regional spot market, or some combination of these resource options. These decisions will also encompass the volumes of each resource to be acquired, based on need, cost, reliability and risk factors. My analysis emphasizes the power purchase component, but considers the other resource options only to the extent of putting the power purchases in context of the resource options available to SSVEC.

An appropriate structure will also clearly indicate the limits on that authority. It may be appropriate for low cost, low volume, low risk resource acquisitions to be addressed at lower levels in the organization, with increasingly higher levels of approval required as the decisions increase in terms of potential impacts.

An appropriate structure will also provide checks and balances to ensure that no single individual has excessive authority and to ensure that potential abuses would be discovered on a timely basis.

Q. What elements should the Commission consider in determining whether SSVEC has appropriately implemented power procurement procedures?

A. Appropriate implementation of power procurement starts with a well-defined statement of objectives.

To achieve these objectives, the Cooperative should develop written and documented formal power procurement procedures. Ideally, top-level management should adopt these written formal procedures to ensure that the procurement procedures are given high priority by those who are responsible for implementing them. As a minimum, the procedures, even if not formally adopted by top-management, should be written to provide guidance to and a benchmark for, measuring the performance of those responsible for procuring power.

Appropriate implementation of power procurement also requires that the power procurement procedures are communicated to those employees responsible for implementing them. To ensure that all relevant employees are aware of the power procurement procedures, the Cooperative should establish training programs, internal communications, job performance criteria and job performance evaluations.

A method to systematically evaluate progress and results is a key element of an appropriately implemented power procurement procedure. This mechanism should monitor the results of the chosen power procurement approach and compare them to the results had other approaches been used. This mechanism should identify opportunities for improvement and stimulate the Cooperative to be open to changing procedures to improve power procurement performance.

Finally, the power procurement procedure should include a mechanism to update the procedure to incorporate improvements and mitigate deficiencies identified in the monitoring phase. This feedback loop is an important feature of an appropriately implemented power procurement procedure. The updating phase creates the expectation that the Cooperative will change its power procurement procedures when conditions warrant (as identified in the monitoring phase).

Organizational Structure

Q. Did you request information from SSVEC to enable you to evaluate its organization relative to power procurement and purchase power procurement process?

A. Yes. I developed a substantial set of data requests addressing these topics and received responses from SSVEC.

Q. In your opinion, are SSVEC's existing organizational structure and power procurement procedures adequate and appropriate?

A. No. In converting from a full requirements contract with AEPCO to a partial requirements service, SSVEC substantially increased its responsibility for ensuring reliable and economic service to its customers. Under the full requirements contract, AEPCO planned for and supplied all of the energy and capacity SSVEC needed. SSVEC's responsibility, related to power procurement under the full requirements contract, was to provide AEPCO with its load forecast. AEPCO was responsible for the rest. Please refer to SSVEC's response to JM 14.10, which is attached as Exhibit JEM-2, page 1.

Under the partial requirements service contract, AEPCO is responsible for supplying the amounts of capacity and energy specified in the contract at the specified prices. AEPCO is but one of SSVEC's sources of electric power, although it currently still supplies most of SSVEC's power. SSVEC is now responsible for ensuring that it has adequate power supplies, from reliable sources at reasonable prices. This includes substantial new responsibilities for conducting the planning for power supplies, including power purchases, for identifying and evaluating power supply alternatives, for selecting their preferred power supplies, including power purchases, and for implementing their decisions. Please refer to SSVEC's responses to JM 14.11 and JM14.12, which are attached as Exhibit JEM-2, pages 2 and 3.

In the responses to my data requests, it does not appear that SSVEC has changed any of its organizational structure or power procurement processes to reflect the new and greater responsibility it now has for ensuring reliable and economic power supplies for its customers.

Q. Please provide more detail regarding SSVEC's organizational structure.

A. In response to data request JM 14.29, which is attached as Exhibit JEM-3, SSVEC indicated that it made no changes to its organizational structure as a result of the change from full to partial requirements services from AEPCO. SSVEC indicated that the new responsibilities were incorporated into the existing positions, as well as contract services with WAPA for scheduling and with GDS for power supply advice. Given the significance and the complexity of the new responsibilities that SSVEC acquired when it ceased being a full requirements customer of AEPCO as of December 31, 2007, I am concerned that SSVEC has not effectuated the necessary institutional changes to ensure sound power supply planning and purchase power procurement.

In essence, it appears that SSVEC has delegated responsibility to WAPA and GDS that it had formerly delegated to AEPCO. Simply delegating the responsibility for planning and procurement to another entity does not ensure that the results will be improved. In fact, there is a distinct possibility that the results will be worse, especially in the short term, given that new working relationships and procedures will need to be developed commensurate with the new entities and responsibilities involved.

Q. Has SSVEC clearly defined who has the authority to make decisions about power supplies and purchases?

A. SSVEC has generally identified the responsible parties/positions in response to JM 14.22, which is attached as pages 1 and 2 of Exhibit JEM-3. It appears that WAPA and SSVEC's consultant, GDS, develop information regarding the type and quantities of power supply products to procure. The CFO and CEO share some responsibilities in a manner not clearly defined in SSVEC's response to JM 14.22. For example, according to paragraph a), the CFO makes the final decision regarding the type and quantities of power supply products. However, that answer also indicates that the CEO is consulted in advance of all purchase decisions, making it unclear whether the CFO or CEO has ultimate authority. The authority issue is further clouded by paragraph e), which states that the CEO approves all major purchases. It is not clear exactly which decisions are made by the CFO and which are made by the CEO.

Q. Has SSVEC clearly defined the extent of authority of each decision-maker regarding purchased power and the limits on that authority?

A. No. Based on Exhibit JEM-3 and interviews, it appears that SSVEC has not defined explicit limits of authority regarding the approvals of power purchases. In many utilities, "major purchases" as referenced in paragraph e would be defined in terms of cost or volume of power purchased, with the CEO approval being required explicitly only for purchases above some specified threshold. In addition, there may be other thresholds of significance in the purchase hierarchy. The smallest purchases may only need approval of the traders, intermediate sized purchases may require additional approvals by mid-level management, larger purchases by the CFO, and the largest purchases by the CEO. This type of explicit structure, which in my experience is usually associated with formal written procurement policies, does not appear to exist at SSVEC.

Another example alluded to in Exhibit JEM-3, paragraph (a) is that GDS and WAPA in some capacity advise the CFO, who has final responsibility. However, the limits of their authority are not clear given that "collectively the group decides." It is also not clear whether or how much information must be formally and reproducibly prepared and provided to the CFO. In other words, it is unclear how much and what information the CFO actually has when making a decision, and whether it is documented or simply verbally discussed.

Also, the CFO's authority and responsibility to provide information to the CEO and the Board of Directors is vague. It appears that most of the information is shared after the purchase has been made, and thus it is not clear how the CEO or Board of Directors would influence a decision before it is actually made.

Q. Does SSVEC's organization contain appropriate checks and balances?

A. Yes, to a degree in that power purchases for SSVEC involve a number of distinct entities that can prevent and identify errors and abuses. These include WAPA, GDS, the CFO, the CEO, and in a more limited fashion, the Board of Directors.

Unfortunately, while the organizational structure contains the opportunities for checks and balances, the potential effectiveness of these checks and balances is reduced due to the lack of formal written procedures and explicitly defined responsibilities and authorities. Developing and approving formal written procurement policies and procedures would force SSVEC to think through potential errors and abuses associated with securing power supplies and how to prevent them. Formal written policies and procedures would both guide the conduct of the decision makers and also provide a benchmark against which to measure the performance of the decision makers.

Power Procurement Procedures

Q. Please explain in more detail your earlier statement that SSVEC's purchase power procurement practices were not adequate and appropriate.

A. I assessed each of the five elements that the Commission should consider regarding SSVEC's purchase power procurement practices. To recap, these five were a clear statement of objectives, written procedures, communicating those procedures to responsible employees, monitoring results, and updating the procedures.

SSVEC's power purchase objectives appear to me to be reliable service at reasonable cost. I have not requested nor received a written statement of specific objectives, but have concluded that these are SSVEC's objectives based on conversations with SSVEC and an observation that these objectives are implicit in the SSVEC's responses to data requests. These are reasonable and appropriate objectives.

Q. Does SSVEC have formal written procedures pertaining to power purchases?

A. No. SSVEC does not have written power procurement procedures, much less formal approval by top-level management of such written procedures. SSVEC relies heavily on WAPA for power procurement, and thus indirectly on WAPA's procedures. It is not clear to what extent WAPA's procedures are customized to meet SSVEC's objectives or best suit SSVEC's customers' interests.

The response to JM 14.18 indicates that SSVEC has no formal power procurement plan or purchase power strategy in place. The response to JM 14.19 indicates that WAPA bases purchase decisions on a number of factors, but SSVEC did not provide (nor even confirm the existence of) a manual, guideline, policy or any other written document to guide electric power procurement personnel. Please refer to Exhibit JEM-4, pages 1 and 2 for copies of SSVEC's responses to JM 14.18 and JM 14.19, respectively.

Even if WAPA has written procedures, SSVEC should also have written procedures that adopt or customize the WAPA procedures. SSVEC's best interests may not always be served by what is in WAPA's best interests. With WAPA acting as the agent for SSVEC, it is important that SSVEC assess whether and how WAPA's interests align with SSVEC's. It is also important that SSVEC unambiguously communicate its interests to WAPA, and that the Cooperative monitor WAPA's performance to ensure that its interests are being protected.

Q. **Does SSVEC have any informal or unwritten guidelines or strategies for purchasing electricity?**

A. No. When asked this question in JM 14.20, SSVEC's response was to refer to the response to JM14.19. Apparently, SSVEC's unwritten guidelines or strategies are to rely on WAPA. Please refer to Exhibit JEM-4, page 3 for a copy of SSVEC's response to JM 14.20.

Q. **Has SSVEC implemented an appropriate mechanism to communicate its power procurement procedures to the responsible personnel?**

A. No, with regard to formal written power procurement procedures, they do not exist.

With regard to informal procurement strategies, SSVEC indicated that it communicates with WAPA "regularly via phone, e-mail, and meetings to develop, monitor, and modify procurement strategies," and that the results of those discussions are communicated to the trading staff. The communication itself is appropriate, but I am concerned that it is too informal and *ad hoc* in nature. As such, it is difficult to ensure that the message has been conveyed as intended to the responsible personnel. It is also virtually impossible to hold anyone accountable when the guidelines/instructions are communicated so informally. Please refer to Exhibit JEM-5 for a copy of SSVEC's response to JM 14.21.

Q. Has SSVEC implemented an appropriate mechanism to monitor the results of power procurement activities?

A. No. SSVEC makes vague references to monitoring power procurement strategies in its response to data requests, e.g., see Exhibit JEM-5. However, making reference to monitoring is not the same as specifying how, when, how often, and by whom monitoring should be done – all of which would be specified in an appropriate power procurement procedure.

Q. Even though SSVEC did not specify a monitoring mechanism, is SSVEC collecting, compiling and analyzing the appropriate data needed to monitor the results of its power procurement activities?

A. No. Ultimately, monitoring the results of its power procurement procedures entails comparing the power purchases (cost, reliability, other indicators) as made under SSVEC's power procurement procedures to other power supply resources and approaches. SSVEC has not compiled even the most basic information necessary to make such a comparison.

In response to data request JM 14.54, SSVEC indicated that it "does not maintain a database of the cost and amount of on-peak and off-peak power available from providers in the region and does not otherwise have this data available to it."

In response to data request JM 14.55, SSVEC indicated that it "does not maintain energy and pricing information for the wesTTrans market."

In data request JM 14.57, SSVEC was asked whether the regional electric market provided electricity supplies that were less expensive than would have been available under the AEPCO full requirements contract. This is one of the fundamental questions – is the partial requirements service from AEPCO to which SSVEC just converted less expensive than retaining full requirements service would have been? SSVEC's response is that it "does not have the AEPCO information available to answer this question."

In summary, SSVEC does not have the information available to assess whether its procurement strategy is yielding higher or lower costs than would be available from other suppliers or from a continuation of its full requirements service beyond January 1, 2008. This information is essential to any real monitoring of its power procurement methods. SSVEC should develop a monitoring mechanism to collect, compile and evaluate this comparative power cost data.

Copies of SSVEC's responses to JM 14.54, JM 14.55 and JM 14.57 are contained in Exhibit JEM-6.

Q. **Has SSVEC implemented an appropriate mechanism to update its power procurement procedures?**

A. No. SSVEC makes vague references to modifying power procurement strategies in its response to data requests, e.g., see Exhibit JEM-5. However, making reference to modifying is not the same as specifying how, when, how often, and by whom updating should be done – all of which would be specified in an appropriate power procurement procedure.

Q. Please summarize your concerns about SSVEC's organization and power procurement procedures.

A. My concern is that the planning and purchase power procurement processes are not written down or formally approved. In essence, the entire planning and purchase power procurement process resides in the minds of a few existing staff, especially the CFO. That is not to say that the current process is necessarily producing bad results or that there is evidence of material error or abuse. Rather the current process fails to provide benchmarks against which to measure performance or real time checks and balances to prevent abuse.

Q. What are your recommendations?

A. I recommend that the Commission direct SSVEC to:

a. Develop written procedures for power supply planning and power procurement and formally approve them, also submitting the written procedures for Staff review and Commission approval;

b. Define and document the responsibilities and limits of authority to make decisions about power supplies and purchases;

c. Establish and document a clearly enforceable set of checks and balances on the authority of personnel involved in power supply planning and power procurement;

d. Formalize and document the communication of power supply planning and procurement strategies and procedures to the responsible personnel;

e. Develop, document and implement a power procurement monitoring mechanism; and

f. Develop and implement a mechanism to review and update power procurement procedures. (When permanent changes in conditions/circumstances warrant).

EXECUTION OF POWER PROCUREMENT PROCEDURES

Did SSVEC appropriately follow its power procurement procedures?

Q. What should the Commission consider in assessing whether SSVEC appropriately followed its power procurement procedures?

A. In general, the Commission should consider three fundamental elements of SSVEC's power procurement procedures to determine whether it was appropriately followed.

First is whether the responsible personnel knew about and followed the power procurement procedures. Factors contributing to this determination could include evidence of employee awareness of procedures/policies, employee actions consistent with those procedures/policies, proper sign-offs by accountable personnel, and internal reviews of the power procurement process.

Second is whether deviations from the power procurement procedures occurred and whether those deviations were appropriate. Factors contributing to this determination could include the existence of a deviation, evidence of a mechanism to monitor changing conditions and circumstances and the ability of existing procedures to cope with them, and evidence that the deviation was justified by the changed circumstances.

Third is whether the power procurement procedures were followed despite changing circumstances and conditions that would have warranted a deviation from power procurement procedures. Factors contributing to this determination could include evidence of a mechanism to monitor changing conditions and circumstances and the ability of existing procedures to cope with them, and evidence that a deviation would have been justified by the changed circumstances.

In summary, the Commission should assess whether SSVEC followed its own procedures. If not, the Commission should assess whether those deviations were appropriate to the changed circumstances. If SSVEC followed its procedures, the Commission should verify that deviations were not appropriate (i.e., that conditions had not changed to warrant a deviation in the procurement procedures).

Q. Did your evaluation conclude that SSVEC appropriately followed its power procurement procedures?

A. No. Because SSVEC did not develop written power procurement policies/procedures to secure power under the new partial requirements service contract, I could not make a determination that SSVEC appropriately followed its power procurement procedures. At this time, SSVEC appears to have unwritten *ad hoc* power procurement procedures which fail to provide a benchmark against which to assess whether SSVEC procured power appropriately.

Q. What do you recommend?

A. I recommend that the Commission require SSVEC to:

a. Develop and formally adopt written power procurement policies/procedures;
b. Develop a mechanism to monitor changing market conditions and make deviations from the adopted policies/procedures when appropriate (temporary changes in conditions/circumstances), also documenting the reasons for those deviations; and
c. Develop a mechanism to update the written policies/procedures when permanent changes in conditions/circumstances warrant.

PURCHASE POWER PRICES RELATIVE TO MARKET

Were SSVEC's power purchases made at prices favorable compared to regional market prices?

Q. Did you determine that SSVEC made power purchases at unreasonable costs?

A. No. As discussed below, SSVEC did not provide the data required to determine whether or not it made power purchases at a reasonable cost.

Q. What should the commission consider in determining whether SSVEC made power purchases at reasonable cost?

A. Typically, in a competitive market, comparing prices paid to market prices is a way to measure whether the prices paid (and cost) were reasonable. The most appropriate way to compare SSVEC's purchases to market prices is on a marginal basis. That is, at any given time, I would analyze how SSVEC's marginal cost of supply compared to the market price at that time.

Q. Were you able to do the marginal cost analysis?

A. No. SSVEC did not possess or have access to the data needed for that analysis. Please refer to Exhibit JEM-6.

Overview of 2008 Power Purchases

Q. Please provide an overview of SSVEC's power purchases.

A. For this purpose, I have categorized SSVEC power purchases as AEPCO partial requirements service, incremental power requirements, and balancing power requirements.

The vast majority of SSVEC's power purchases, by energy purchased and by cost, is under the partial services contract with AEPCO. Under the contract, SSVEC is allocated a

31.8 percent share of AEPCO capacity and associated energy. That is adequate to meet all of SSVEC's loads except for the summer months of May through September. This power is purchased from AEPCO at regulated Schedule A rates, and as such are average rates designed to recover AEPCO costs. Because they are average rates, one might expect the price to be below market prices when the market demand is high and above market prices when market demand is low.

SSVEC expects to purchase a relatively small amount of incremental power during the months of May through September from third party suppliers. This power is purchased at negotiated prices, which should reflect market prices. WAPA and GDS (SSVEC's consultant) identify third party purchase opportunities and make purchase recommendations to SSVEC's CFO.

The third category of purchases is power purchased and sold to balance SSVEC's power supplies and loads. WAPA administers the balancing power service for SSVEC. Assuming that WAPA is monitoring the regional markets appropriately, power bought or sold by WAPA on behalf of SSVEC should by definition be at the market price at the time of the purchase or sale.

There is a potential for some redundancy between AEPCO and WAPA regarding balancing power. The AEPCO partial service contract also provides for power under Schedule B, which is to supply power above the allocated capacity of Schedule A. AEPCO prices Schedule B power, if taken, at its cost of supply. If AEPCO purchases power to meet Schedule B requirements, it should be priced at market prices (which in theory should be the same prices WAPA would purchase balancing power).

Q. Has SSVEC purchased Schedule B power from AEPCO?

A. No. SSVEC did not purchase Schedule B power from AEPCO in the months of January through November 2008. SSVEC indicates that Schedule B prices are above market prices that are available to it through WAPA balancing services, and thus are never selected.

Based on AEPCO's assertion that Schedule B pricing is only to make AEPCO whole for its incremental costs, Schedule B pricing should be at market prices if AEPCO purchases power to supply Schedule B demands. If AEPCO supplies Schedule B power first from any available capacity not already allocated elsewhere, it is possible that Schedule B power could be above the market price because the cost of AEPCO's marginal capacity was out of the money. If that is how AEPCO actually supplies Schedule B power, AEPCO would not be providing the least-cost power under Schedule B.

Purchased Power Cost

Q. Please describe your analysis of SSVEC's purchase power costs for 2008.

A. I analyzed SSVEC's fuel adjustor reports for the months of January through October 2008. First, I examined the major cost components driving the monthly fuel adjustor, which were AEPCO (Schedule A) purchases, WAPA balancing purchases and services, third party power purchases, and Southwest Transmission Cooperative transmission services. In order to determine how each component varied month-to-month and to identify which one(s) were responsible for significant cost increases that occurred in June-August of 2008, I first looked at the total cost per month. Total cost per month shows the combined effects of changes in volumes purchased and changes in purchase prices.

Q. What did this analysis of the January through October 2008 period show?

A. Exhibit JEM-7 Page 1 shows the total monthly costs expended on purchased power (energy and demand), transmission services, dispatch, reactive power, etc. – all of the elements contained in the fuel and purchase power costs adjustor. Several things should be noted from Exhibit JEM-7 Page 1:

a. The total cost is strongly peaked in June-August, with June costs being roughly double the February costs.

b. The AEPCO costs are essentially constant, showing little month-to-month variation. The largest AEPCO monthly cost occurred in October.

c. The Southwest Transmission Cooperative costs are essentially constant, showing little month-to-month variation.

d. The WAPA[1] costs show significant variation, and contributing significantly to the peak costs in the June-August time period.

e. The third party purchases, from Public Service of New Mexico ("PNM") in May and Arizona Public Service ("APS") in June-August, contribute significantly to the peak cost period.[2]

Q. Is it surprising that the total cost is strongly peaked in June-August?

A. No. Obviously, we would anticipate that SSVEC would spend more money during the summer peak period, since it must purchase more power then to supply the higher summer demands.

---

[1] Kirby Chapman of SSVEC indicated that the WAPA power purchases are day ahead and same day purchases used to balance load. WAPA handles the dispatch for SSVEC, and secures additional power or sells excess depending on changing daily conditions.

[2] Kirby Chapman indicated that the block purchases made by SSVEC will sometimes appear as part of the WAPA bill and other times separately, depending how they were paid for. It would appear that those purchases separately identified in the adjustor report are purchases that can be attributed to the change to partial requirements service.

Purchased Power Amounts

Q. Have you analyzed how the amount of power SSVEC purchased varied by month in 2008?

A. Yes. Exhibit JEM-7 Page 2 shows the KWh **purchased** for each month of 2008 by source. The Commission should note several things from Exhibit JEM-7 Page 2:

a. The monthly quantity of energy purchased is highest in June, with July and August at similar levels.

b. The purchases from AEPCO are essentially constant, and all under Schedule A, showing little month-to-month variation.

c. Purchases from WAPA were highest in the June through September period, and varied noticeably from month-to-month.

d. Identifiable third party purchases were made only in May through August, to contribute the supplies needed to meet the summer peak.

Average Purchase Price Analysis

Q. How did the average price of power SSVEC purchased from each source compare?

A. Exhibit JEM-7 page 3 shows the average cost of power SSVEC purchased from AEPCO, WAPA and third party suppliers. I considered only the energy and demand component (no ancillary services) for each source and divided by the number of kWh obtained from that source to get the average cost of power. The noteworthy observations from Exhibit JEM-7 page 3 include:

a. AEPCO average costs per kWh are nearly constant from January through September 2008. A substantial price increase occurred in October as AEPCO's fuel and purchase power cost adjustor increased from $0.01305 to $0.02551 per kWh. The member energy rate and demand charges were unchanged.

b. It does not appear that AEPCO prices are responsible for the increase in SSVEC's rates over the summer. AEPCO supplied essentially constant amounts of energy at essentially constant prices through September.

c. The WAPA power supplies are more expensive than those of AEPCO for the months of January-August. This is to be expected, since WAPA is buying and selling day ahead or same day power at real time market prices. I would anticipate that the market prices, especially during times of regional summer peak, would be set by gas fired combustion turbines (and some combined cycle gas plants). Purchases from AEPCO are under rate Schedule A and include much energy from coal plants, the operating cost of which is less costly than that of gas plants.

d. WAPA power supplies are indicative of the real time market prices – if SSVEC simply bought from the real time market instead of securing longer-term supplies (which it currently does through AEPCO and third party suppliers). Market prices were high though July, and dropped off since August (probably coinciding with the decline in natural gas prices).

e. SSVEC's block purchases from PNM and APS are at much higher average costs per kWh than either the average WAPA balancing purchases or the AEPCO purchases.

f. Over the months of June-August, when SSVEC's customers began to express concerns over large bill increases, SSVEC received significant quantities of power from WAPA, at an average cost per kWh about 50% higher than from AEPCO.

g. Over the months of June-August, SSVEC received significant quantities of power from Third Party Suppliers, at an average cost per kWh more than twice that from AEPCO.

Q. Can you conclude from your analysis that SSVEC purchased power from third party suppliers at unreasonable or imprudent prices?

A. No, but I also cannot rule it out based on my analysis of average costs. Since the third party purchases are for incremental power needs over the summer months above the supplies available under the AEPCO partial requirements service, it would be more appropriate to analyze and compare the costs of alternative sources of incremental supply. In other words, if the third party suppliers that SSVEC selected were the least cost of any potential suppliers of the incremental power need, then they may have well been prudent even if they are much more expensive than the average cost of AEPCO Schedule A power. In the same way, it is possible that the third party suppliers were less expensive, or more reliably available, than the spot market would have been for the same amount of power.

Spot Market Price Analysis

Q. Have you conducted further analysis?

A. Yes. In response to data request JM 14.56, SSVEC provided WAPA purchases and sales made to balance SSVEC's supplies to its loads. SSVEC provided the cost and volume of each balancing purchase and sale by WAPA for each day for the months of January through October 2008. I calculated the average price of power for each transaction in May through August, which are the months during which SSVEC entered into third party purchase contracts. Assuming that WAPA buys and sells balancing power at market prices, the WAPA balancing transaction prices represent a daily picture of the spot market prices against which the third party prices can be compared.

The WAPA balancing transaction prices are a reasonable, though incomplete indication of the spot market prices. The WAPA data do not reflect the spot market at times that

WAPA was not engaged in balancing transactions on behalf of SSVEC. The WAPA balancing transaction data are not broken out hourly, only by on-peak and off-peak. Thus using the WAPA balancing transaction price data does not permit the evaluation of instantaneous spot prices, but does permit assessment of on- and off-peak period market prices.

Q. What did you do with the WAPA balancing transactions data?

A. I developed scatter plots of the on-peak and off-peak price by day for each month. There were multiple transactions per day at different prices, perhaps reflecting price differences in the time of day of the transaction or with whom the transaction was conducted.

I then determined the price of the third party purchases, which were [redacted] during the months of May through August. As such, these purchases [redacted] could be compared to the on-peak and off-peak prices of WAPA balancing transactions.

Q. What did your analysis show?

A. My analysis shows that the price of electricity under SSVEC's third party contracts was at the high end of the range of spot market prices (as estimated by WAPA balancing transaction prices). Exhibit JEM-8 shows the prices of WAPA on- and off-peak purchase transactions (scatter plot) in comparison to the third party contract price for the months of May through August (pages 1 through 4, respectively).

Of the [redacted] WAPA balancing transactions in May 2008, only [redacted] were at prices greater than the price SSVEC paid under its third party power contract with Public Service of New Mexico. See Exhibit JEM-8, page 1.

Of the [redacted] WAPA balancing transactions in June 2008, only [redacted] were at prices greater than the price SSVEC paid under its third party power contract with Arizona Public Service Company. See Exhibit JEM-8, page 2.

Of the [redacted] WAPA balancing transactions in July 2008, only [redacted] were at prices greater than the price SSVEC paid under its third party power contract with Arizona Public Service Company. See Exhibit JEM-8, page 3.

Of the [redacted] WAPA balancing transactions in August 2008, [redacted] at a price greater than the price SSVEC paid under its third party power contract with Arizona Public Service Company. See Exhibit JEM-8, page 4.

In summary from May through August 2008, the spot market was less costly than SSVEC's negotiated third party contract on 90% of the occasions that WAPA initiated a balancing purchase on SSVEC's behalf.

Q. Earlier in your testimony you indicated that you would expect the average prices to be above the off-peak prices but below the on-peak market prices. Is that what you found regarding the third party contracts?

A. No. [redacted] The third party contracts were generally above on-peak market prices (as estimated from WAPA balancing purchases and sales) as shown in Exhibit JEM-9. It is interesting to note that there were [redacted] occasions in the on-peak period during which WAPA sales occurred at a price greater than the price SSVEC paid to third parties for the power. In other words, in most cases in which SSVEC had excess power for sale on peak, it was sold at prices below those SSVEC was paying simultaneously to buy the power from third party suppliers.

As expected, the third party contracts were generally above off-peak market prices (as estimated from WAPA balancing purchases and sales) as shown in Exhibit JEM-10. It is interesting to note that there were a few occasions that the off-peak market prices were above the third party contract price. There were no instances in which the off-peak WAPA balancing sales were at prices equal to or greater than the price SSVEC paid to third parties for the power. In other words, to the extent that SSVEC had excess power for sale off peak when it was simultaneously buying power from third party suppliers, it was sold at prices below those SSVEC was paying to the third party suppliers.

Q. Is this an expected result?

A. No. I would expect the contract prices to be closer to the spot market prices when there is adequate generating capacity and the spot market is capable of providing reliable power supplies. In 2008, it is my understanding that the regional market was not facing capacity constraints and was considered both liquid and adequate.

SSVEC indicated that the third party suppliers were selected in response to a solicitation made to potential suppliers. See response to data request JM 14.43 on page 1 of Exhibit JEM-11. SSVEC further indicated that it had always selected the lowest cost resource. See response to data request JM 14.36 on page 2 of Exhibit JEM-11.

Reasonableness of Third Party Purchase Power Costs

Q. Does this mean that SSVEC's third party power costs in 2008 were indicative of future costs SSVEC will incur to serve load?

A. No. I believe that SSVEC will in the future be able to reduce its prices for third party power to relatively lower levels than were negotiated by SSVEC for 2008. This is mainly due to the fact that 2008 was a transition period for SSVEC, moving from full requirements to partial requirements service. I would expect that as SSVEC gains more experience, and suppliers in the regions have more experience with SSVEC in its new role of planning for and procuring power supplies, it will improve upon its 2008 performance.

Q. Please explain.

A. In my opinion, SSVEC has not fully stepped up to the challenges of its new planning and procurement responsibilities in making its 2008 purchase decisions.

- SSVEC considered only short-term resources, including the reliance on the spot market and short-term purchases. SSVEC had not considered long-term resources, including ownership of generation and multi-year purchase power agreements. SSVEC intends to consider these options in the future according to its response to data request JM 14.46 (See Exhibit JEM-12). Presumably, SSVEC would pursue those resource options if they reduce cost compared to short term purchases, and thus will put a relative downward pressure on future costs (assuming these resources are reasonably evaluated and implemented). Implementation of an integrated resource planning process, now lacking, would be a major step toward SSVEC developing a comprehensive spectrum of resource options.
- Negotiated third party supply prices were above spot market prices. This is due in part to the timing of the third party contracts which were negotiated at a time of high natural gas prices, in effect locking in higher gas prices when the electric spot market

was dropping in response to dropping gas prices. SSVEC issued a request for indicative prices to potential suppliers on April 22 for purchases to begin in May. There are options available to SSVEC regarding when and for what products RFPs are issued. Implementation of a formal written procurement procedure would be a major step toward SSVEC securing the appropriate product at the appropriate price.

- SSVEC has limited experience in regard to power procurement choices and processes. As previously indicated, SSVEC had limited experience in 2008 with its new roles and responsibilities. I would expect that as SSVEC gains experience, its procedures and strategies would evolve leading to lower costs. Perhaps as importantly, as potential suppliers gain experience with SSVEC, they may be more willing to offer power supplies with terms better suited to SSVEC's needs.

Q. Are the purchased power costs SSVEC incurred in summer of 2008 indicative of the future purchased power costs?

A. No. The AEPCO costs, WAPA balancing costs and third party power costs incurred by SSVEC in 2008 are not likely to be indicative of future power costs.

AEPCO costs are determined by Commission regulated rates, which have increased beginning in October 2008. Thus the January through September 2008 AEPCO costs will not be representative of, and will be less than, future costs. Since the Commission sets AEPCO's rates, the Commission is well aware of the amount and timing of increases likely and can take that into account when setting SSVEC's base rates.

WAPA balancing power costs are determined by electric market prices. Electric market prices are dependent on natural gas prices, which were abnormally high and very volatile in the April through July 2008 period, but which have significantly decreased since that period. As a consequence, WAPA balancing power costs in 2008 will not be representative of, and are likely to be more than, future costs. Even if SSVEC changed to a source of balancing services other than WAPA, that source would still buy and sell power at the market price and I would not expect that to vary much between alternative suppliers of balancing services.

Third party power purchase costs are the result of negotiated prices influenced by SSVEC's planning and procurement processes. As previously discussed, SSVEC's power planning and procurement processes are in transition and are not currently formalized or well-documented. As experience is gained and SSVEC implements and improves processes, it is likely that relative costs will decrease. For these reasons, the 2008 third party prices are not representative of, and are likely to be higher than, future third party contracts.

Q. What are your recommendations to the Commission?

A. I recommend that the Commission:

a. Find that the third party power supplies secured by SSVEC in lieu of remaining a full service customer of AEPCO were at substantially higher prices than power supplies from AEPCO.

b. In an effort to reduce the relative cost of third party power supplies, direct SSVEC to formalize and upgrade its power planning process to ensure it appropriately considers the full spectrum of resources available to it.

c. In an effort to reduce the relative cost of third party power supplies, direct SSVEC to formalize and upgrade its power procurement process to ensure it identifies and appropriately implements available resources and holds SSVEC accountable (e.g., timing of purchases and RFPs, optimize purchases and sales).

d. Direct SSVEC to verify and document that WAPA balancing transactions are conducted at market prices and that they are done in a manner consistent with SSVEC's interests.

ALTERNATIVE APPROACHES

Are there alternative approaches that would be more appropriate to ensure that SSVEC's purchased power costs are prudent and reasonable?

Q. What factors should the Commission consider in assessing whether alternate procurement approaches exist that are better able to ensure that SSVEC's purchase power costs are prudent and reasonable?

A. The ultimate question is what procurement process would most benefit SSVEC's customers. Although there is insufficient data at this time to establish whether the move to partial requirements will have a positive impact on purchase power costs on a long-term basis, it is clear that enhanced and formalized procurement procedures would improve SSVEC's chances of obtaining power at a prudent and reasonable cost.

The Commission should consider two elements in assessing the ultimate question. First, did SSVEC's customers benefit from the conversion from full requirements in 2008, the period for which we now have actual data? Second, what else might SSVEC do to improve, or achieve, benefit from the move from full requirements service?

Benefits of Move to Partial Requirements Service

Q. Did SSVEC demonstrate a benefit in 2008 from its move to partial requirements service?

A. No. While the move would in theory provide the opportunity to utilize markets to improve upon the full requirements service offering by AEPCO, it appears that SSVEC was not able to secure power at low enough prices to benefit its customers in 2008. In fact, my estimate is that the move to partial requirements service actually increased costs for SSVEC's ratepayers.

Q. Please describe your analysis.

A. My analysis focuses on the power SSVEC secured from third party suppliers and from AEPCO (under the partial requirements service agreement) in January through October 2008. I assumed that the WAPA balancing transactions and balancing power costs would have remained the same even if SSVEC had purchased the rest of its power under a full requirements service agreement with AEPCO. I compared the actual partial requirements and third party power costs to an estimate of the cost of an equivalent amount of power under a full requirements service agreement with AEPCO.

The pricing of power under a full requirements service agreement with AEPCO is different from the pricing of power under a partial service requirements agreement. To estimate the cost of supplying all the energy under a full requirements contract with AEPCO, I applied AEPCO's full service tariffs to the energy SSVEC purchased from third party suppliers and AEPCO partial requirements service. Since AEPCO's rates are regulated, the energy and demand charges and the adjustors are known. Scenario 1 in my analysis assumed that AEPCO could supply the incremental power (that SSVEC purchased from third party suppliers) in January through October 2008 at the same average cost embedded in AEPCO's existing rates for full requirements service.

It is unlikely that AEPCO could supply the incremental power at the average cost, with the result that over time AEPCO's rates would be adjusted to cover the cost of securing additional capacity and energy. To estimate this effect, I analyzed Scenario 2, which made the assumption that AEPCO would secure the incremental power at the spot market prices. The spot market prices in May through August 2008 (when incremental power is a factor) were higher than AEPCO's prices; I assumed that AEPCO would ultimately recover these higher costs for the incremental power from SSVEC.

Q. What are the results of your analysis?

A. I found that Scenario 1, full requirements from AEPCO at AEPCO's existing rates, would have been nearly $3 million cheaper over the January through October 2008 period than the costs SSVEC actually incurred. However, this probably overstates the potential savings in that AEPCO's rates would probably have to increase over time as the cost of serving more incremental load under higher fuel costs phased in.

Scenario 2, full requirements from AEPCO with AEPCO charging for incremental power procured from the spot market at market rates, reflects a savings potential that may be more sustainable over time. I found that Scenario 2 would have been nearly $0.5 million cheaper over the January through October 2008 period than the costs SSVEC actually incurred. Scenario 2 may overstate the cost of power to SSVEC in that the incremental power costs under full requirements service probably would be shared by all AEPCO customers rather than to be allocated solely to SSVEC.

Nonetheless, Scenarios 1 and 2 represent a reasonable range of costs to SSVEC for power under a full requirements contract. For January through October 2008, SSVEC's procurement of power from third parties resulted in higher costs for SSVEC customers than either Scenario 1 or Scenario 2 full requirements service from AEPCO.

Alternatives to Improve Benefits

Q. Regarding the second question, what else might SSVEC do to improve, or achieve, benefit from the move from full requirements service?

A. The Commission should consider several elements in response.

- Procedures: As indicated previously in my testimony, SSVEC has the opportunity to improve on its 2008 performance by upgrading and documenting its power planning and procurement processes. This would enable SSVEC to efficiently take advantage of market opportunities.
- Market assessment: The electricity market needs to be vibrant and liquid to provide SSVEC with the opportunity to improve upon the AEPCO full requirements service. If it is not, the market will not be a reliable source of inexpensive power. During periods of ample or excess capacity, market prices may be quite low, but as the capacity is more fully utilized, prices can become volatile and high. The most effective alternatives available to SSVEC are likely to change as markets tighten.

Q. Based on its market assessment, will SSVEC be able to continue its reliance on the spot market as it did for much of 2008?

A. No. In response to data request JM 14.46 (See Exhibit JEM-12), SSVEC indicates that while the markets are liquid for the next few years, on the longer term it has concerns as reserve margins decline. As a result, "SSVEC is studying long term purchased power options, long term joint generation ownership options, and also the development of a local peaking generation facility."

Q. Are these appropriate options for SSVEC to study?

A. Yes, these are appropriate physical hedges to market prices which would be normally considered as part of the integrated resource planning process. However, SSVEC should also remain open to other options, including:

- Demand response programs and energy efficiency programs to reduce market exposure.
- Financial hedges and laddered purchasing strategies to reduce market price volatility.
- Return to full requirements service if SSVEC cannot demonstrate an actual benefit from utilizing electricity markets to supplement partial requirements services from AEPCO.

Q. Has SSVEC utilized financial hedges?

A. No, it has not. In response to data request JM 14.24, SSVEC indicated that it has not used financial instruments in the purchase of power supplies. It appears that SSVEC is open to considering financial hedges under the appropriate conditions, but that such conditions have not occurred to date. See Exhibit JEM-13.

Q. Does this conclude your direct testimony?

A. Yes it does.

JERRY E. MENDL
President
MSB Energy Associates

AREAS OF EXPERTISE

- Analysis of energy resource adequacy, cost and availability
- Evaluation of alternative energy resource options
- Analysis of electric utility bulk power supplies
- Analysis of electric utility projected merger savings and implications on system operations and costs
- Transmission system analysis
- Service delivery and markets in a restructured electric utility industry

EDUCATION

1973 B.S. Degree in Nuclear Engineering, With Very High Honors, from the University of Wisconsin, Madison, Wisconsin

1974 M.S. Degree in Nuclear Engineering from the University of Wisconsin, Madison, Wisconsin.

EXPERIENCE

1987-Present
President
MSB Energy Associates, Inc.
Middleton, Wisconsin

Since co-founding MSB Energy Associates in 1988, Mendl has served public-sector clients in Arizona, Kentucky, California, Utah, Nevada, Washington, Texas, Alaska, Iowa, Illinois, South Carolina, Connecticut, Massachusetts, Vermont, Maryland, Michigan, Missouri, Minnesota, Louisiana, Wisconsin, Pennsylvania, Georgia, Hawaii, Ohio, New Jersey, the District of Columbia and Ontario. Much of his recent work has involved electric utility restructuring, low-income consumer energy affordability and service issues, prudence of gas and electric utility planning and purchase practices, and analyzing need for transmission lines. He assesses "green pricing" tariffs for renewable electric resources and fuel/purchase power costs for electric and natural gas utility rate cases and renewable energy alternatives for utility construction cases. He evaluates electric utility restructuring alternatives and prepares restructuring policy recommendations and supporting technical information. He analyzes long-range plans and planning methods used by gas and electric utilities. He prepares and presents reports, recommendations and testimony.

He conducted engineering, environmental, economic and life-cycle cost analyses of alternate energy resource options, including improved end-use energy efficiency and renewable resources. Mendl developed state regulatory commission codes for implementing integrated resource planning and evaluated the adequacy of existing and proposed codes. Mendl was both organizer and presenter for a series of five least-cost planning workshops across the U.S. sponsored by the National Association of Regulatory Utility Commissioners (NARUC). He also participated in five Conservation Law Foundation collaborative projects in the northeastern states.

1974-1988

Administrator, Division of Systems Planning, Environmental Review and Consumer Analysis (1979-1988)
Director, Bureau of Environmental and Energy Systems (1976-1979)
Public Service Engineer (1974-1976)
State of Wisconsin, Public Service Commission
Madison, Wisconsin

Mendl was employed by the Wisconsin Public Service Commission for 14 years (1974-1988), and was responsible for the development and evolution of Wisconsin's long-range planning process for electric utilities. He had overall responsibility for directing the Commission's activities concerning utility long-range plans. In addition, Mendl had overall responsibility for and directed the preparation of environmental impact statements and environmental assessments, identifying expected impacts as well as evaluating alternatives, for five large power plants, numerous transmission lines, a major natural gas pipeline, and many policy issues including Electric Space Heat, Electric Utility Tariffs, Electric Sales Promotion, Small- Power Production and Cogeneration, and Extension of Service. Mendl was also responsible for directing the preparation of major studies, including *The Alternative Electric Power Supply Study, Alternative Electric Power Supply - Update*, and *Utility SO_2 Cleanup - Cost and Capability*. (The *Alternative Electric Power Supply Study* and *Update* identified renewable energy, load management and energy efficiency resources that would economically meet Wisconsin's long term electricity needs.) Mendl testified before the Wisconsin Commission in rate cases, planning cases, construction certificate cases and policy cases. He also appeared before other state Commissions and the Federal Energy Regulatory Commission.

OTHER DISTINCTIONS

Mendl staffed the NARUC Subcommittee on Energy Conservation for two and one-half years, and was closely involved with the preparation of the *Least-Cost Planning Handbook for Public Utility Commissioners*.

Mendl also was appointed to serve a four-year term on the Research Advisory Committee of the National Regulatory Research Institute (NRRI). One of seven regulatory staff selected nationally, Mendl helped NRRI to shape its research agenda to be more useful and responsive to the regulatory community.

Mendl is a Registered Professional Engineer in the State of Wisconsin.

TESTIMONY

Mendl, since co-founding MSB Energy Associates in 1988, has testified in the following proceedings:

Submitted To:	Subject	Docket No.	Date
Nevada Public Utilities Commission	Nevada Power Energy Supply Plan Update	08-08030	2008
Nevada Public Utilities Commission	Sierra Power Energy Supply Plan Update	08-08031	2008
Nevada Public Utilities Commission	Sierra Power gas and electric fuel and power cost recovery practices (DEAA)	08-02043 & 08-02044	2008
Nevada Public Utilities Commission	Nevada Power fuel gas and power cost recovery practices (DEAA)	08-02042	2008

Nevada Public Utilities Commission	Westpac Utilities fuel purchase practices and costs (including merging of utility LPG and natural gas rates)	07-05019 & 07-05020	2007
Nevada Public Utilities Commission	Nevada Power Amendment to 2006 IRP and Energy Supply Plan update forward sales proposal	07-07013	2007
Nevada Public Utilities Commission	Sierra Pacific Power approval of 2007 IRP forward sales proposal	07-06049	2007
Nevada Public Utilities Commission	Southwest Gas fuel procurement practices and setting DEAA rate	07-05015	2007
Georgia Public Service Commission	Georgia Power IRP 2007 demand side management plan, energy efficiency and cost tests	24505-U	2007
Nevada Public Utilities Commission	Nevada Power fuel gas and power purchase practices (BTER & DEAA)	07-01022	2007
Nevada Public Utilities Commission	Sierra Pacific Power fuel gas and power purchase practices (BTER & DEAA)	06-12001	2007
Arizona Corporation Commission	UNS Gas prudence of gas procurement practices	G-04204A-05-0831	2007
Nevada Public Utilities Commission	Westpac Utilities fuel purchase practices and costs (BTER & DEAA)	06-05016 & 06-05017	2006
Nevada Public Utilities Commission	Nevada Power Integrated Resource Plan - gas purchase strategies	06-06051	2006
Nevada Public Utilities Commission	Sierra Pacific Power Energy Supply Plan - gas purchase strategies	06-07010	2006
Wisconsin Public Service Commission	Strategic Energy Assessment - electrical adequacy through 2012	5-ES-103	2006
Nevada Public Utilities Commission	Nevada Power fuel gas and power purchase practices (DEAA)	06-01016	2006
Nevada Public Utilities Commission	Sierra Pacific Power fuel gas and power purchase practices (DEAA)	05-12001	2006
Michigan Public Service Commission	MichCon gas cost recovery factor, contingent factor, and purchase acquisition strategy	U-14717	2006
Michigan Public Service Commission	Consumers gas cost recovery factor, contingent factor, and purchase acquisition strategy	U-14716	2006
Nevada Public Utilities Commission	Nevada Power fuel gas and power purchase practices (BTER)	06-01016	2006
Nevada Public Utilities Commission	Sierra Pacific Power fuel gas and power purchase practices (BTER)	05-12001	2006
Nevada Public Utilities Commission	Nevada Power gas purchase practices – Energy Supply Plan	05-9017	2005

Nevada Public Utilities Commission	Sierra Pacific Power gas purchase practices – Energy Supply Plan	05-9016	2005
Michigan Public Service Commission	Consumers gas cost recovery factor, contingent factor, and purchase acquisition strategy	U-14403	2005
Michigan Public Service Commission	MichCon gas cost recovery factor, contingent factor, and purchase acquisition strategy	U-14401	2005
Kentucky Public Service Commission	Analysis of need for and electrical alternatives to EKPC Cranston-Rowan County transmission line	2005-00089	2005
Nevada Public Utilities Commission	Nevada Power gas purchase practices	04-9004	2004
Nevada Public Utilities Commission	Sierra Pacific Power gas purchase practices	04-7004	2004
Nevada Public Utilities Commission	Prudence of Southwest Gas PGA costs, purchase practices	03-12012	2004
Michigan Public Service Commission	MichCon gas cost recovery factor, contingent factor, and purchase acquisition strategy	U-13902	2004
Wisconsin Public Service Commission	WPS rate case, low income programs, Weston 4 pre-certification expenses and capital	6690-UR-115	2003
Wisconsin Public Service Commission	Alliant rate case, RiverSide purchase power cost and incentive, Columbia maintenance and outages	6680-UR-113	2003
Wisconsin Public Service Commission	Alliant rate case, RockGen purchase power savings bonus, coal procurement	6680-UR-112	2002
Wisconsin Public Service Commission	Assess fuel and purchase power issues in WPS rate case	6690-UR-114	2002
Wisconsin Public Service Commission	Assess fuel and purchase power issues in MG&E rate case	3270-UR-111	2002
Wisconsin Public Service Commission	Assess renewable energy and other alternative resources in WE Power the Future –Port Washington case	05-CE-117	2002
Wisconsin Public Service Commission	Assess costs related to formation and operation of American Transmission Company	05-EI-129	2002
Wisconsin Public Service Commission	Filed comments in investigation of purchase power incentive mechanisms	05-EI-131	2002
Wisconsin Public Service Commission	Alliant rate case, adequacy of planning, purchase power contracts, coal contracts	6680-UR-111	2002

Michigan Public Service Commission	Analyze proposed gas cost recovery factor and plan, and gas procurement practices.	UR-13060	2002
Wisconsin Public Service Commission	WPS rate case, fuel costs, adequacy of planning, purchase power	6690-UR-113	2002
Wisconsin Public Service Commission	Alliant fuel cost rate case, adequacy of planning, purchase power contracts	6680-UR-110	2001
Wisconsin Public Service Commission	Wisconsin Electric fuel rate case, fuel costs, adequacy of planning, purchase power contracts	6630-UR-111	2001
Wisconsin Public Service Commission	Rulemaking regarding electric utility fuel and purchased power cost recovery	1-AC-197	2001
Wisconsin Public Service Commission	Nuclear spent fuel dry cask storage expansion at Point Beach	6630-CE-275	2000
Wisconsin Public Service Commission	WPS rate case, fuel costs, adequacy of planning, purchase power	6690-UR-112	2000
Wisconsin Public Service Commission	Alliant fuel cost rate case, adequacy of planning, prudence of plant maintenance practices, purchase power	6680-UR-110	2000
Wisconsin Public Service Commission	Rulemaking regarding environmental impact analysis and public input process	1-AC-185	1999
Michigan Public Service Commission	Over-recovery of revenues due to declining coal costs	U-11560	1999
Michigan Public Service Commission	Reasonableness of proposed settlement regarding recovery of nuclear plant replacement power costs through power cost recovery factor, suspension of factor	U-11181-R	1999
Michigan Public Service Commission	Fuel and purchase power surcharge, coal costs	U-11180-R	1998
Vermont Public Service Board	Prudence of Green Mountain Power purchase and management of Hydro-Quebec power	5983	1997
Michigan Public Service Commission	Analysis of coal costs, purchase practices, spot market	U-10971-R	1997
Michigan Public Service Commission	Suspension of the fuel and purchase power factor and planning in the transition to restructured utilities	U-11453	1997
Wisconsin Public Service Commission	IEC merger (of WPL/IES/IPC), need and environmental issues regarding proposed Mississippi River transmission crossings	6680-UM-100	1997
Pennsylvania Public Utility Commission	Restructuring, stranded cost, and securitization -- economic and	R-00973877	1997

	environmental issues		
Michigan Public Service Commission	Fuel and purchase power surcharge, impact of sales promotion	U-11181	1997
Wisconsin Public Service Commission	Primergy merger (of WEPCO/NSP), impact on state regulatory authority	6630-UM-100/4220-UM-101	1996
Michigan Public Service Commission	Gas cost recovery adjustments	U-10640-R	1996
Pennsylvania Public Utility Commission	Electric discounted rates, gas/electric competition	R-943280C0001	1996
Michigan Public Service Commission	Fuel and purchase power surcharge, impact of WEPCO/NSP merger	U-10966	1996
Michigan Public Service Commission	Fuel and purchase power surcharge, impact of energy efficiency	U-10971	1996
Minnesota House Committee on Taxes	Impact of cogeneration project on NSP ratepayers	HF637	1996
Minnesota Senate Committee on Jobs, Energy and Community Development	Impact of cogeneration project on NSP ratepayers	SF1147	1996
Wisconsin Public Service Commission	Role of DSM in Advance Plan-7 in light of potential restructuring	05-EP-7	1995
City Public Service Board of San Antonio	Integrated resource planning process (1992 EPAct hearings)	NA	1994
Maryland Public Service Commission	1992 EPAct rules	8630	1994
Georgia Public Service Commission	Commercial and Industrial DSM programs for Savannah Electric	4135-U	1993
Public Utilities Commission of Ohio	Analysis of forecasts and long range plans for Ohio Power and Columbus Southern (case settled)	90-659-EL-FOR and 90-660-EL-FOR	1990
Georgia Public Service Commission	Integrated resource plan analyses for Georgia Power and Savannah Electric	4131-U and 4134-U	1992
New Orleans City Council	Least-cost planning rules	14629 MCS	1991
District of Columbia Public Service Commission	Potomac Electric least-cost plan analysis	834 Phase II	1990
Massachusetts Department of Public Utilities	Boston Gas plan integrated resource plans	90-55	1990
Massachusetts Department of Public Utilities	Boston Gas commercial and industrial DSM, cost recovery	90-320	1991
Hawaii Public Service Commission	Least-cost resource planning	6617	1991

Georgia Public Service Commission	Least-cost planning and facility certification rules	4047-U	1991
New Jersey Board of Public Utilities Commissioners	Transmission line certificate (case settled)	NA	1990
South Carolina Public Service Commission	Transmission line certificate	88-519-E	1988
Vermont Public Service Board	Least-cost planning	5270	1988
D.C. Public Service Commission	Least-cost planning	834	1987

Mendl also assisted in preparing testimony and testified in numerous cases as a senior staff witness at the Wisconsin Public Service Commission. Dates are approximate.

- Advance Plans 1 through 4 (Dockets 05-EP-1 through 05-EP-4 -- on various occasions between 1977 and 1988) before the Wisconsin Public Service Commission
  - A wide variety of planning issues including forecasts, nuclear vs coal power, alternative energy, renewable energy, load management, transmission planning, demand-side management resources, principles and methods of integrated resource planning

- Rate Cases (various occasions between 1976 and 1988) including landmark time-of-use rate case (6630-ER-2) for Wisconsin Electric Power

  Environmental and consumer impacts of rate levels and alternative rate designs before the Wisconsin Public Service Commission

- Construction Cases before the Wisconsin Public Service Commission

  Pleasant Prairie Power Plant (1976-1978)
  Germantown Combustion Turbines (1976-1977)
  Weston 3 (1979)
  Edgewater 5 (1980)
  Apple River -- Crystal Cave Transmission Line (1980)
  Prairie Island -- Eau Claire Transmission Line (1981-1982)
  North Madison -- Huiskamp -- Sycamore Transmission Line (1982)
  Point Beach Nuclear Plant Steam Generator Replacement (1982)
  Wisconsin Natural Gas Pipeline (1986)

  Need for power, appropriateness of the utility proposals, and the comparative economics of alternatives, environmental impacts

- Other Appearances while employed at the Wisconsin Public Service Commission

  Planning investigation before the Connecticut Department of Public Utilities Control Authority (1975); uranium availability and resource alternatives
  Rulemaking proceedings before Wisconsin Legislative Committees (1975-1982); planning, siting, and environmental impact analysis rules
  Tyrone Nuclear Project Termination cost recovery hearing before the Federal Energy Regulatory Commission (1980)
  Acid Rain legislation before Wisconsin Legislative Committees (1984-1985)

SELECTED CLIENTS

Mendl has served the following public sector clients since 1988.

Client	Nature of Service
Alaska Housing Finance Corporation	Analysis of applicability of EPAct standards to Alaska resource selection process.
American Public Power Association	Prepared whitepaper on distributed resources, "Distributed Resources: Options for Public Power" and presented it to APPA National Meeting and distributed resources workshops.
Arizona Corporation Commission	Analyze UNS Gas fuel procurement practices, provide testimony regarding prudence, and develop auditor training manual. Analyzed Sempra request to be allowed to compete for selected retail loads. Analyzed Sulphur Springs Valley Electric Coop purchase power practices.
California Low Income Governing Board	Analysis of options to deliver energy efficiency and assistance programs to low-income households in a restructured utility environment. Assist Board to develop low-income programs and policies under interim utility administration.
City of Chicago	Evaluate municipalization, especially regarding power availability and cost, transmission constraints, cogeneration potential.
Citizen's Utility Board of Wisconsin	Evaluate energy efficiency and load management programs in light of possible industry restructuring. Evaluate fuel rate cases and recommend revenue reductions in testimony for Alliant, Wisconsin Electric, Madison Gas & Electric and Wisconsin Public Service. Assess ATC formation and operation costs. Comment on and develop fuel rules, purchase power incentives. MISO collaborative
Center for Neighborhood Technologies	Analysis of value of avoiding generation, transmission and distribution through energy efficiency, load management and distributed generation.
Clean Wisconsin	Review Strategic Energy Assessments, provide comments to Wisconsin PSC
Conservation Law Foundation of New England	Collaboratives with Boston Edison, United Illuminating, Eastern Utilities Association, and Nantucket Electric regarding system planning approaches, avoided costs, resource screening. Collaborative with Green Mountain Power regarding Vermont Yankee end-of-life planning.
Dane County Energy Collaborative	Technical contractor to collaborative analyzing 345 kV transmission proposal and alternatives to meet Dane County energy needs.
District of Columbia Energy Office	Analysis of DC Natural Gas' and PEPCo's integrated resource planning.
District of Columbia Public Service Commission	Testimony regarding least cost planning principles and rules.
Environmental Law and Policy Center	Analyzed potential impacts of proposed merger of Wisconsin Electric Power Company and Northern States Power Company on state regulatory authority in Wisconsin and Minnesota. Analyzed

	environmental impacts related to proposed merger of WPL and two Iowa utilities (IES and IPC), including the proposed transmission line crossings of Mississippi River and changes in air pollutant emissions. Analyzed electric and gas energy efficiency plans in Iowa and Illinois
Environmentalists/Penn. Energy Project	Analyzed PECO application to securitize stranded costs, especially on economic and environmental impacts that could result from authorizing overestimated stranded costs. Analyzed utility retail access pilot programs. Analyzed restructuring plans for PECO and PP&L.
Germantown Settlement, Philadelphia	Advise regarding business structure and market to aggregate load and/or provide energy efficiency and energy assistance services to low-income households.
Georgia Public Service Commission	Developed integrated resource planning and facility certification rules. Developed integrated resource plans and reviewed utility filings. Monitored utility DSM programs. Evaluated GP demand side plan for 2007 IRP. Analyzed DSM selection process in DSM Working Group setting on behalf of Commission Staff.
Hawaii Division of Consumer Advocacy	Developed integrated resource planning rules.
Illinois Citizens Utility Board	Analyzed Illinois electric supply auction, suggested modifications to better incorporate energy efficiency and demand response resources.
Iowa Department of Natural Resources	Developed and implemented workshops to train building operators and architects in energy efficiency and renewable energy resource opportunities.
Kentucky Public Service Commission	Analyzed need and alternatives for an EKPC transmission line and a prepared report. Presented testimony defending and explaining report. Analyzed need and alternatives for an AEP transmission line and a prepared report.
Lake Michigan Coalition	Analyzed nuclear spent fuel dry cask storage expansion proposal
Maryland Public Service Commission	Reviewed two utility long-range plans and suggested improvements.
Massachusetts Division of Energy Resources	Analysis of Boston Gas Co. integrated resource plans and residential energy efficiency programs. Analysis of Boston Gas's commercial and industrial energy efficiency programs.
Michigan Community Action Agency Association	Analysis of Michigan electric utility restructuring proposals and impacts on retail prices. Analysis of MichCon gas cost recovery case and factor. Analyses of Indiana-Michigan, Consumers Energy, Wisconsin Electric and Northern States Power-Wisconsin power supply cost recovery cases and factors, including analysis of coal and power purchase practices, demand-side management, and nuclear plant outage costs. Analysis of Northern States Power/Wisconsin Electric Power Co. proposed merger.
Missouri Public Service Commission	Developed rules for electric resource planning and gas resource planning. Evaluated three electric utility plans filed pursuant to rules.

National Association of Regulatory Utility Commissioners	Organized, prepared and presented at five workshops throughout the U.S. sponsored by NARUC/DOE.
Natural Resources Defense Council, Mid-Atlantic Energy Project Collaborative	Evaluated resource planning and selection processes used by PSE&G to prepare plan filings.
New Jersey Department of the Public Advocate	Analyzed a transmission line application.
City of New Orleans	Developed least cost planning rules, guided a public working group to develop demand-side programs.
Nevada Office of Attorney General, Bureau of Consumer Protection	Sierra Pacific Power and Nevada Power Energy Supply Plans, Base Tariff Energy Rates and Deferred Energy Adjustment Accounts - gas purchase practices and prudence; Southwest Gas and Westpac PGA prudence analysis, gas purchase practices
Nevada Public Utilities Commission, Regulatory Operations Staff	Southwest Gas PGA prudence analysis, gas purchase practices
Northeast States for Coordinated Air Use Management	Electric vehicle analysis.
Ohio Office of Consumer Council	Analyzed two utilities' long-range plans and energy efficiency resource options.
Ontario Energy Board	Evaluated need for natural gas integrated resource planning rules.
The Opportunity Council	Evaluated gas DSM programs to be considered by Cascade Natural Gas in Washington.
Pennsylvania Office of Consumer Advocate	Evaluated demand-side management programs for several electric utilities. Investigated causes of Winter Emergency of 1994. Analyzed electric "flexible rates" and gas/electric competition issues. Analyzed electric reliability concerns in a restructured and competitive market.
RENEW Wisconsin	Analyzed MG&E's green pricing tariff, compared costs of conventional resources to green resources to determine whether a green premium tariff was appropriate
Responsible Use of Rural and Agricultural Land (RURAL)	Evaluated air and licensing issues related to a proposed power plant. Evaluated Public Service Commission proposed environmental and siting rule changes. Analyzed rules governing environmental review and public comment process and provided testimony before PSCW.
South Carolina Office of Consumer Advocate	Analyzed a transmission line application.

Southeast Wisconsin Energy Initiative	Technical contractor to collaborative analyzing 345 kV transmission proposal and alternatives to meet energy needs in southeastern Wisconsin.
Texas ROSE	Developed electric planning rules. Analyzed city of San Antonio resource plan.
U.S. Environmental Protection Agency	Developed handbook, "Energy Efficiency and Renewable Energy: Opportunities from Title IV of the Clean Air Act", which focuses on how energy efficiency and renewables relate to acid rain compliance strategies.
U.S. Environmental Protection Agency and U.S. Department of Energy	Analyzed and compared utility supply- and demand-side resource selection for Clean Air Act compliance on the Pennsylvania-New Jersey-Maryland (PJM) interconnection.
Utah Committee on Consumer Services	Analyzed DSM cost recovery mechanism, avoided cost methods, cost effectiveness tests, assisted in settlement discussions and would have prepared testimony if issues not settled.
Vermont Natural Resources Council and Vermont Public Interest Research Group	Testimony regarding least cost planning principles and rules.
Vermont Public Service Board	Testimony regarding the prudence of Green Mountain Power's planning and management of the Hydro-Quebec power purchase.
Wisconsin Department of Administration	Analysis of new home characteristics built in northeastern Wisconsin, permit data, survey development and report
Wisconsin's Environmental Decade	Review of Draft Environmental Impact Statement of major 345 kV transmission line in northwestern Wisconsin, develop comments.

**RESPONSE OF SSVEC
TO ARIZONA CORPORATION COMMISSION
STAFF'S FOURTEENTH SET OF DATA REQUESTS
DOCKET NO. E-01575A-08-0328**

December 15, 2008

JM 14.10 **Please describe SSVEC's purchase power planning and procurement responsibilities under its former full requirements contract with AEPCO.**

Response: SSVEC had no wholesale power procurement responsibilities under its former full requirements contract with AEPCO. AEPCO provided all of SSVEC's power needs. SSVEC's planning responsibilities were generally limited to preparing an annual load forecast and providing the results to AEPCO.

Prepared by: David M. Brian, P.E.
GDS Associates, Inc.
1850 Parkway Place, Suite 800
Marietta, Georgia 30067

RESPONSE OF SSVEC
TO ARIZONA CORPORATION COMMISSION
STAFF'S FOURTEENTH SET OF DATA REQUESTS
DOCKET NO. E-01575A-08-0328

December 15, 2008

JM 14.11 **Please describe SSVEC's purchase power planning and procurement responsibilities under its current partial requirements contract with AEPCO.**

Response: Under the contract, SSVEC has responsibility for purchasing from AEPCO electric energy and capacity (at rates set forth in Exhibit A-1 to Rate Schedule A) scheduled by SSVEC or its scheduling agent, up to its Allocated Capacity ("AC"). SSVEC has to take and pay, or pay for such electric energy and capacity under the terms and conditions set forth in the agreement at rates and charges established in the agreement and Rate Schedule A.

The entitlements to power and energy under the agreement do not fully supply SSVEC's load during peak periods, and thus SSVEC is responsible for planning for and procuring wholesale power needs above that provided by AEPCO in order to meet peak loads.

Prepared by: David M. Brian, P.E.
GDS Associates, Inc.
1850 Parkway Place, Suite 800
Marietta, Georgia 30067

**RESPONSE OF SSVEC
TO ARIZONA CORPORATION COMMISSION
STAFF'S FOURTEENTH SET OF DATA REQUESTS
DOCKET NO. E-01575A-08-0328**

December 15, 2008

JM 14.12 **Please explain in detail how SSVEC's purchase power planning and procurement responsibilities changed when its status changed from the full requirements contract with AEPCO to a partial requirements contract.**

Response: The partial requirements contract defines the quantities that SSVEC is entitled to purchase from AEPCO. The contract contains detailed exhibits that specify the amounts of power and energy available to SSVEC and that AEPCO is obligated to supply. These amounts are defined on a monthly basis through 2020, and there are provisions that define hourly availability as well. Prior to obtaining partial requirements status, SSVEC engaged WAPA to act as its scheduling agent when partial requirements status was achieved. WAPA provides scheduling and energy management services under contract. WAPA schedules the power and energy available under the AEPCO contract, makes day-to-day real time marketing decisions such as whether to purchase power from the wholesale market rather than purchase it from AEPCO, whether to buy power on the market to supplement the AEPCO supply, or whether to make third party wholesale sales sourced by the AEPCO supply.

Commensurate with converting to a partial requirements member, SSVEC also changed its balancing area authority. SSVEC's loads were previously contained within the AEPCO/SWTC pseudo balancing area within the WAPA balancing authority. SSVEC, AEPCO, SWTC, and WAPA agreed to electronically remove the SSVEC load from the AEPCO/SWTC balancing area and instead locate it within the host WAPA balancing authority. SSVEC now settles loads and resources under the terms of the WAPA Open Access Transmission Tariff. Regulation and imbalance services are provided by the WAPA balancing authority.

Power supply planning is now independently undertaken by SSVEC. SSVEC projects its future power supply needs and compares that to the entitlement it has to purchase power from AEPCO. Future capacity and energy deficits based on this comparison fall to SSVEC to plan for and meet.

Prepared by: David M. Brian, P.E.
GDS Associates, Inc.
1850 Parkway Place, Suite 800
Marietta, Georgia 30067

9372216.1

RESPONSE OF SSVEC
TO ARIZONA CORPORATION COMMISSION
STAFF'S FOURTEENTH SET OF DATA REQUESTS
DOCKET NO. E-01575A-08-0328

December 15, 2008

JM 14.29 **Please explain in detail whether and how SSVEC's organizational structure related to purchase power acquisition changed given the changed responsibilities in going from the full requirements contract with AEPCO to a partial requirements contract.**

Response: SSVEC has not made changes to its organizational structure as a result of the conversion to partial requirements service. Some additional responsibilities are carried by existing positions however. The CEO retains overall management and decision-making authority for power supply decisions. The Chief Financial and Administrative Officer oversees the day-to-day power procurement, scheduling, and sales activities. SSVEC manages the remaining workload through contract services with WAPA as its scheduling and GDS Associates, Inc. as its power supply consultant.

Prepared by: David M. Brian, P.E.
GDS Associates, Inc.
1850 Parkway Place, Suite 800
Marietta, Georgia 30067

**RESPONSE OF SSVEC
TO ARIZONA CORPORATION COMMISSION
STAFF'S FOURTEENTH SET OF DATA REQUESTS
DOCKET NO. E-01575A-08-0328**

December 15, 2008

Planned Power Procurement Approach and Organization

JM 14.18 **Does Sulphur Springs Valley Electric Cooperative, Inc. (SSVEC) have a formal electric purchase power procurement strategy or purchase power supply plan? If yes, please provide a copy.**

Response: SSVEC does not have a formal power procurement plan in place. WAPA offers marketing advice with regards to wholesale transactions to SSVEC. WAPA is continually monitoring the power forwards market looking for opportunities to hedge SSVEC's power needs.

Prepared by: Kirby Chapman
Sulphur Springs Valley Electric Cooperative
Chief Financial and Administrative Officer
311 E. Wilcox Drive
Sierra Vista, AZ 85635

**RESPONSE OF SSVEC
TO ARIZONA CORPORATION COMMISSION
STAFF'S FOURTEENTH SET OF DATA REQUESTS
DOCKET NO. E-01575A-08-0328**

December 15, 2008

JM 14.19 **Does SSVEC have a manual, guideline, policy, risk-management policy, or any other written documents to guide its electric purchase power procurement personnel in their day-to-day purchase decisions? If so, please provide a copy of all such documents.**

Response: WAPA's Energy Management and Marketing Office's ("EMMO") purchase decisions are based on a number of different factors. Some of these factors are: Price or time targets guidelines provided to by SSVEC, Load and Resource Analysis data, Current and Historical Price data, Risk strategies developed with the customer, and application of commonly accepted economic principles. WAPA's EMMO staff has been delegated authority by WAPA's Regional Manager to enter into and administer certain types of power purchase and sales agreements. Specific trading limits and controls have been defined and are monitored.

Prepared by: Kirby Chapman
Sulphur Springs Valley Electric Cooperative
Chief Financial and Administrative Officer
311 E. Wilcox Drive
Sierra Vista, AZ 85635

9372216.1

**RESPONSE OF SSVEC
TO ARIZONA CORPORATION COMMISSION
STAFF'S FOURTEENTH SET OF DATA REQUESTS
DOCKET NO. E-01575A-08-0328**

December 15, 2008

JM 14.20 **Does SSVEC have any informal or unwritten guidelines or strategies for purchasing electricity? If so, please describe them.**

Response: Please see response to JM 14.19

Prepared by: Kirby Chapman
Sulphur Springs Valley Electric Cooperative
Chief Financial and Administrative Officer
311 E. Wilcox Drive
Sierra Vista, AZ 85635

Exhibit ____(JEM-5)

RESPONSE OF SSVEC
TO ARIZONA CORPORATION COMMISSION
STAFF'S FOURTEENTH SET OF DATA REQUESTS
DOCKET NO. E-01575A-08-0328

December 15, 2008

JM 14.21 **How are SSVEC's written and/or informal procurement strategies communicated to the procurement personnel responsible for day-to-day purchase decisions?**

Response: WAPA's EMMO staff and SSVEC communicate regularly via phone, email, and meetings to develop, monitor, and modify procurement strategies. The results of these meetings are communicated to the trading staff through formal/informal training, emails, meetings, and guidelines.

Prepared by: Kirby Chapman
Sulphur Springs Valley Electric Cooperative
Chief Financial and Administrative Officer
311 E. Wilcox Drive
Sierra Vista, AZ 85635

**RESPONSE OF SSVEC
TO ARIZONA CORPORATION COMMISSION
STAFF'S FOURTEENTH SET OF DATA REQUESTS
DOCKET NO. E-01575A-08-0328**

December 15, 2008

JM 14.54 **What was the cost and amount available of on-peak and off-peak power during the January through October 2008 timeframe from other providers in the region?**

Response: SSVEC does not maintain a database of the cost and amount of on-peak and off-peak power available from providers in the region and does not otherwise have this data available to it.

Prepared by: David M. Brian, P.E.
GDS Associates, Inc.
1850 Parkway Place, Suite 800
Marietta, Georgia 30067

**RESPONSE OF SSVEC
TO ARIZONA CORPORATION COMMISSION
STAFF'S FOURTEENTH SET OF DATA REQUESTS
DOCKET NO. E-01575A-08-0328**

December 15, 2008

JM 14.55 **Please provide energy and power pricing information for energy supplies available through the wesTTrans market from January through October 2008.**

Response: SSVEC does not maintain energy and pricing information for the wesTTrans market.

Prepared by: Kirby Chapman
Sulphur Springs Valley Electric Cooperative
Chief Financial and Administrative Officer
311 E. Wilcox Drive
Sierra Vista, AZ 85635

**RESPONSE OF SSVEC
TO ARIZONA CORPORATION COMMISSION
STAFF'S FOURTEENTH SET OF DATA REQUESTS
DOCKET NO. E-01575A-08-0328**

December 15, 2008

JM 14.57 **Has the regional electric market provided electricity supplies that were less expensive than supplies that would have been available under the AEPCO full requirements contract? Please explain and document your answer.**

Response: SSVEC does not have the AEPCO information available to answer this question.

Prepared by: Kirby Chapman
Sulphur Springs Valley Electric Cooperative
Chief Financial and Administrative Officer
311 E. Wilcox Drive
Sierra Vista, AZ 85635

**RESPONSE OF SSVEC
TO ARIZONA CORPORATION COMMISSION
STAFF'S FOURTEENTH SET OF DATA REQUESTS
DOCKET NO. E-01575A-08-0328**

December 15, 2008

JM 14.49 **Please provide the on-peak and off-peak spot market prices for purchase power since January 1, 2005, for the regional market accessible to SSVEC. Please provide the market prices and the estimated transmission service prices separately and combined for a total delivered market price. Please provide this information on a daily basis, or in as much detail as is available to SSVEC.**

Response: SSVEC does not maintain a database of on-peak and off-peak spot market prices and does not have this data available to it at the present time.

Prepared by: David M. Brian, P.E.
GDS Associates, Inc.
1850 Parkway Place, Suite 800
Marietta, Georgia 30067

RESPONSE OF SSVEC
TO ARIZONA CORPORATION COMMISSION
STAFF'S FOURTEENTH SET OF DATA REQUESTS
DOCKET NO. E-01575A-08-0328

December 15, 2008

JM 14.50 **Please provide the on-peak and off-peak power prices for purchase power under the AEPCO full requirements contract for the period January 1, 2005, through December 31, 2007. Please provide the power and the transmission service prices separately and combined for a total delivered market price.**

Response: SSVEC does not have the on-peak and off-peak pricing for purchase power under the AEPCO full requirements contract.

Prepared by: Kirby Chapman
Sulphur Springs Valley Electric Cooperative
Chief Financial and Administrative Officer
311 E. Wilcox Drive
Sierra Vista, AZ 85635

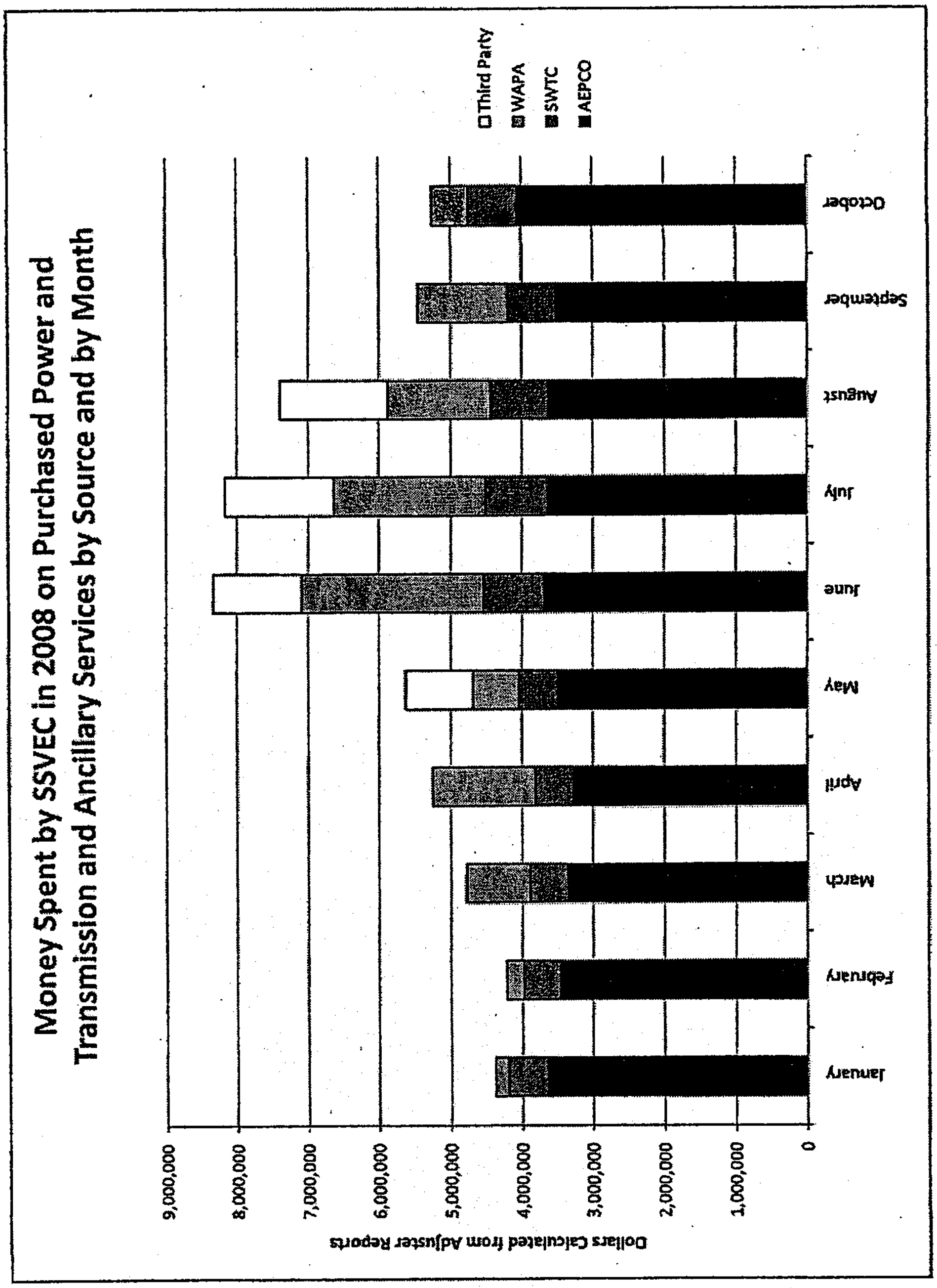
**RESPONSE OF SSVEC
TO ARIZONA CORPORATION COMMISSION
STAFF'S FOURTEENTH SET OF DATA REQUESTS
DOCKET NO. E-01575A-08-0328**

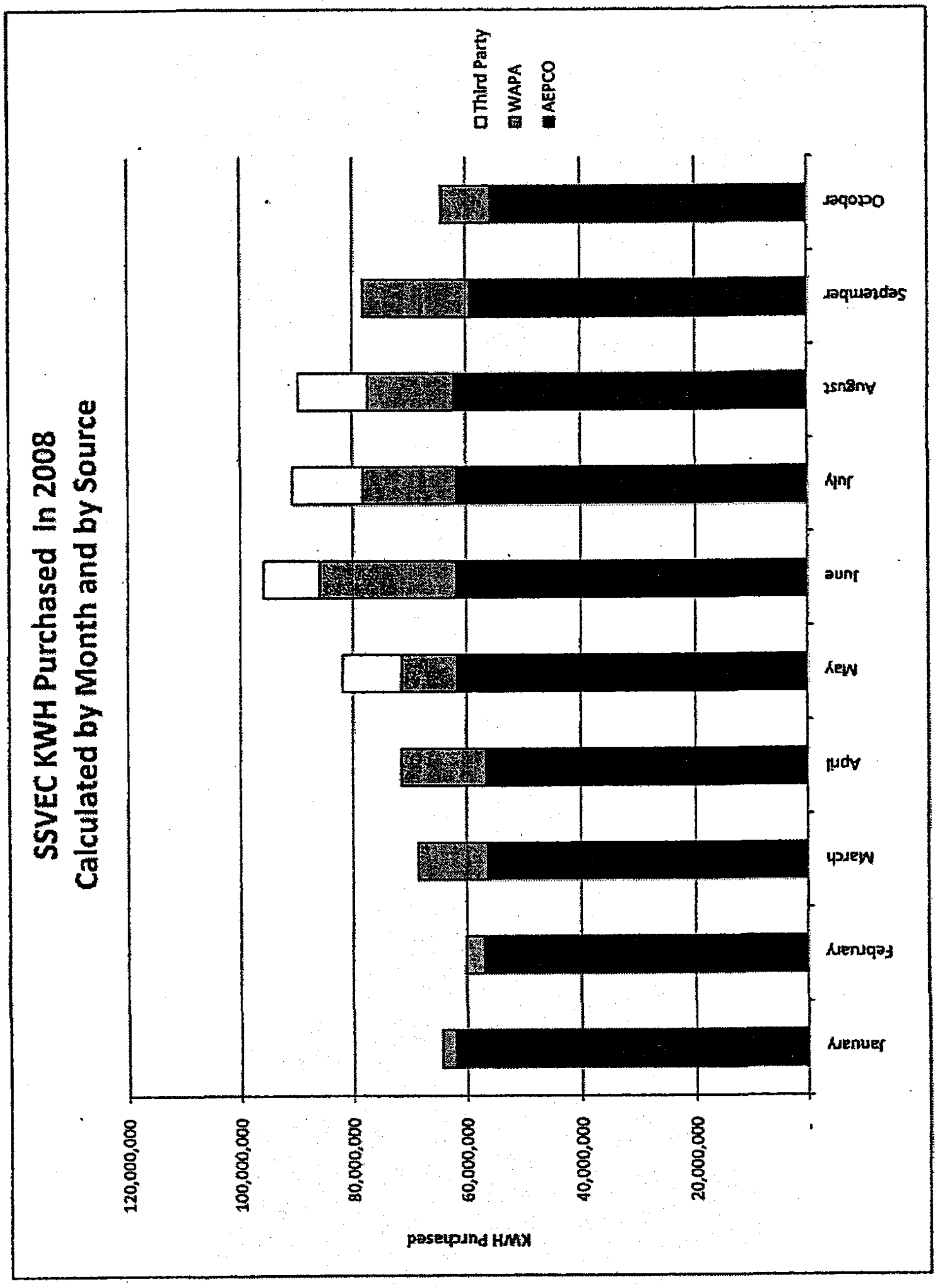
December 15, 2008

JM 14.51 **Please provide the on-peak and off-peak power prices for purchase power under the AEPCO partial requirements contract since January 1, 2008. Please provide the power and the transmission service prices separately and combined for a total delivered market price.**

Response: See Response to JM 14.50.

Prepared by: Kirby Chapman
Sulphur Springs Valley Electric Cooperative
Chief Financial and Administrative Officer
311 E. Wilcox Drive
Sierra Vista, AZ 85635


Money Spent by SSVEC in 2008 on Purchased Power and Transmission and Ancillary Services by Source and by Month
Third Party
WAPA
SWTC
AEPCO
Dollars Calculated from Adjuster Reports
9,000,000
8,000,000
7,000,000
6,000,000
5,000,000
4,000,000
3,000,000
2,000,000
1,000,000
0
January
February
March
April
May
June
July
August
September
October


SSVEC KWH Purchased In 2008
Calculated by Month and by Source
Third Party
WAPA
AEPCO
KWH Purchased
120,000,000
100,000,000
80,000,000
60,000,000
40,000,000
20,000,000
-
January
February
March
April
May
June
July
August
September
October

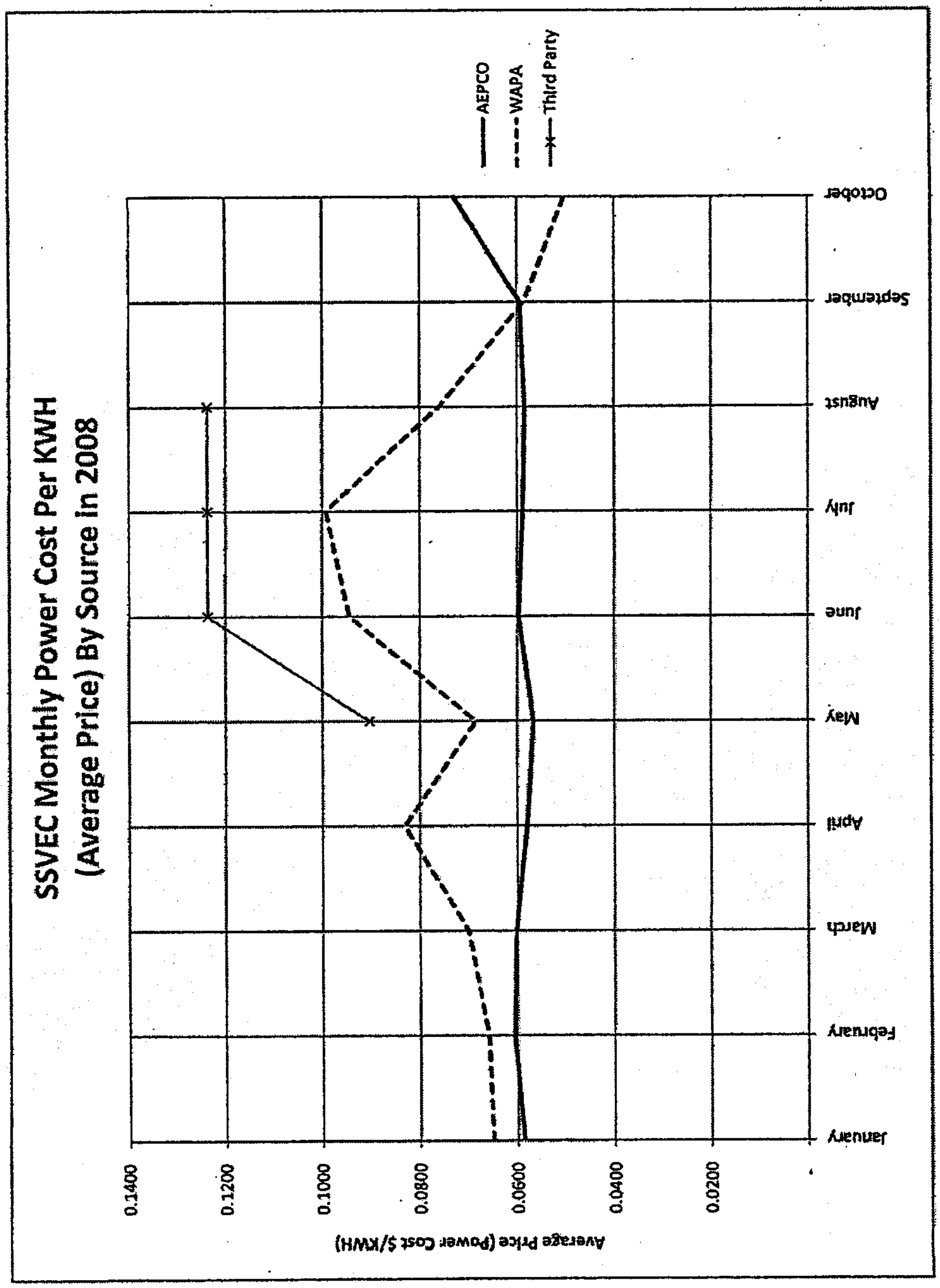

SSVEC Monthly Power Cost Per KWH
(Average Price) By Source in 2008
AEPCO
WAPA
Third Party
Average Price (Power Cost $/KWH)
0.1400
0.1200
0.1000
0.0800
0.0600
0.0400
0.0200
January
February
March
April
May
June
July
August
September
October

Exhibit ____ (JEM-10)

Redacted Four pages of Confidential Material

**RESPONSE OF SSVEC
TO ARIZONA CORPORATION COMMISSION
STAFF'S FOURTEENTH SET OF DATA REQUESTS
DOCKET NO. E-01575A-08-0328**

December 15, 2008

JM 14.43 **What potential suppliers of purchase power has SSVEC identified? How did SSVEC determine who was a potential supplier?**

Response: SSVEC is open to trading with all suppliers that will offer power at the Four Corners, Westwing, & Greenlee. The supplier pool changes by season because of the amount of generation or positions each supplier has at each hub. Typically an e-mail is sent requesting indicative pricing. Those suppliers that reply are the suppliers an RFP is sent to. Examples of potential suppliers that have been identified include APS, Constellation, Powerex, PNM, TEP, Shell, Morgan Standley, and Cargill.

Prepared by: Kirby Chapman
Sulphur Springs Valley Electric Cooperative
Chief Financial and Administrative Officer
311 E. Wilcox Drive
Sierra Vista, AZ 85635

**RESPONSE OF SSVEC
TO ARIZONA CORPORATION COMMISSION
STAFF'S FOURTEENTH SET OF DATA REQUESTS
DOCKET NO. E-01575A-08-0328**

December 15, 2008

JM 14.36 **Did SSVEC select a higher price bid, on the basis of criteria other than cost, during the January 2008 through present period?**

a) **For each bid from a purchase power supplier for electricity delivered in the January 2008 through present time frame, what were the reasons for the bid either being accepted or rejected?**

b) **Please explain each situation in which a higher price bid was selected over a lower price bid.**

Response: No

Prepared by: Kirby Chapman
Sulphur Springs Valley Electric Cooperative
Chief Financial and Administrative Officer
311 E. Wilcox Drive
Sierra Vista, AZ 85635

RESPONSE OF SSVEC
TO ARIZONA CORPORATION COMMISSION
STAFF'S FOURTEENTH SET OF DATA REQUESTS
DOCKET NO. E-01575A-08-0328

December 15, 2008

JM 14.46 **In SSVEC's opinion, is the regional wholesale electricity spot market vibrant and liquid enough to acquire all of its power purchases (above that supplied by AEPCO under the partial requirements contract) from the spot market? Please explain and document.**

Response: Thus far and for the next few years, yes. In SSVEC's view there is sufficient competition in the regional wholesale electricity spot market. SSVEC has been able to select from a number of competitive alternatives at some of the region's trading hubs such as Four Corners, Palo Verde, and Westwing. Longer term SSVEC has concerns. WECC reserve margins have been projected to decline, and the effects of new generation development activities are uncertain. And to the extent that there have been challenges in procuring wholesale power, it has been on the transmission side. There is limited available transmission service in southern Arizona during peak periods, and transmission availability has dictated where and from whom SSVEC has purchased power. For these reasons, SSVEC does not anticipate being able to rely heavily on the regional spot markets during peak periods in the future, and instead expects to secure needs for peak periods on a forward basis well ahead of the peak periods where the needs exist. Along these lines, SSVEC is studying long term purchased power options, long term joint generation ownership options, and also the development of a local peaking generation facility.

Prepared by: David M. Brian, P.E.
GDS Associates, Inc.
1850 Parkway Place, Suite 800
Marietta, Georgia 30067

Exhibit ____(JEM-13)

RESPONSE OF SSVEC
TO ARIZONA CORPORATION COMMISSION
STAFF'S FOURTEENTH SET OF DATA REQUESTS
DOCKET NO. E-01575A-08-0328

December 15, 2008

JM 14.24 **Regarding the use of financial instruments (including puts and calls, futures, etc.) in the acquisition of purchase power supplies:**

a) Did SSVEC use financial instruments in the acquisition of its purchase power supplies for the January 2008 through present period?

b) Has SSVEC ever used financial instruments in the acquisition of its purchase power supplies?

c) Please explain the types of financial instruments, if any, used by SSVEC for the January 2008 through present sales period.

d) If SSVEC previously used financial instruments but did not use them for supplies since January 2008, please explain why.

e) Please explain when SSVEC considers financial instruments appropriate to use and when they are not appropriate to use.

Response:

a. No.

b. No.

c. There were none.

d. Not applicable.

e. Financial instruments are appropriate to use when price risk cannot be effectively and economically managed through the use of physical price hedging. An example would be where a customer is forced to take spot price risk and has no other way than financial instruments to hedge that risk. Thus far SSVEC has not experienced a need to utilize financial hedges to manage risk, as suppliers have provided pricing options that limit SSVEC's exposure to price risk.

Prepared by: David M. Brian, P.E.
GDS Associates, Inc.
1850 Parkway Place, Suite 800
Marietta, Georgia 30067

EXHIBIT

S-5

admitted

BEFORE THE ARIZONA CORPORATION COMMISSION

KRISTIN K. MAYES
Chairman
GARY PIERCE
Commissioner
PAUL NEWMAN
Commissioner
SANDRA D. KENNEDY
Commissioner
BOB STUMP
Commissioner

IN THE MATTER OF THE APPLICATION OF SULPHUR SPRINGS VALLEY ELECTRIC COOPERATIVE, INC. FOR A HEARING TO DETERMINE THE FAIR VALUE OF ITS PROPERTY FOR RATEMAKING PURPOSES, TO FIX A JUST AND RESASONABLE RETURN THEREON, TO APPROVE RATES DESIGNED TO DEVELOP SUCH RETURN AND FOR RELATED APPROVALS.	DOCKET NO. E-01575A-08-0328

DIRECT

TESTIMONY

OF

PREM K. BAHL

ELECTRIC UTILITIES ENGINEER

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

FEBRUARY 17, 2009

TABLE OF CONTENTS

EXHIBITS

EXECUTIVE SUMMARY
SULPHUR SPRINGS VALLEY ELECTRIC COOPERATIVE, INC.
DOCKET NO. E-01575A-08-0328

Prem Bahl's testimony makes recommendations regarding the Arizona Corporation Commission ("Commission" or "ACC") Utilities Division Staff's ("Staff") position in the case of SSVEC Electric Cooperative, Inc.'s ("SSVEC" or "Cooperative") application for a general rate increase. In conjunction with Staff's engineering evaluation, Staff gives an account of its inspection of SSVEC's distribution system, of SSVEC's current operations and maintenance, and of SSVEC's future plans to upgrade and expand its system. Staff also reviews SSVEC's Cost of Service Study ("COSS"). Staff has the following conclusions and recommendations:

CONCLUSIONS

Based on Staff's engineering inspection of SSVEC's electric system, and evaluation and analysis of SSVEC's Cost of Service study results, Staff concludes as follows:

1. That SSVEC:
   a. is operating and maintaining its electrical system properly,
   b. is carrying out system improvements, upgrades and new additions to meet the current and projected load of the Cooperative in an efficient and reliable manner,
   c. has an acceptable level of system losses consistent with the industry guidelines,
   d. is working with the Cochise County Transmission study group to implement the directions issued in the 5th BTA Order (Decision No. 70635),
   e. has a satisfactory record of service interruptions in the historic period between 2004 and 2007, showing an average of 2.09 outage hours per consumer per year,
   f. has evaluated numerous options regarding the Sonoita Reliability Project ("SRP") and its associated 69kV line to Sonoita. The proposed SRP will improve service reliability in Sonoita, Patagonia and Elgin service areas.
2. That SSVEC has used its COSS model for the bundled rate filing appropriately. The model used by SSVEC is consistent with what the Commission approved for use in another cooperative rate case.

3. That, based on the evaluation of the COSS model utilized by SSVEC, the results are satisfactory.

RECOMMENDATIONS

Based on the aforementioned conclusions, Staff recommends that:

1. SSVEC work with other entities, such as Arizona Public Service Company, Tucson Electric Company, and Southwest Transmission Cooperative to establish "continuity" of service, as ordered by the Commission in the fifth BTA in Decision No. 70635, in the Cochise County area, including the Sierra Vista area.
2. SSVEC continue to upgrade its 69 kV sub-transmission and distribution system to improve system performance and reliability for its members.
3. SSVEC continue with its wooden pole replacement program.
4. Commission accept SSVEC's Cost of Service Study for use in this case.

INTRODUCTION

Q. Please state your name and business address.

A. My name is Prem K. Bahl. My business address is 1200 West Washington Street, Phoenix, Arizona 85007.

Q. By whom and in what capacity are you employed?

A. I am employed by the Arizona Corporation Commission ("Commission") as an Electric Utilities Engineer.

Q. Please describe your educational background.

A. I graduated from the South Dakota State University with a Masters degree in Electrical Engineering in May 1972. I received my Professional Engineering ("P.E.") License in the state of Arizona in 1978. My Bachelor of Science degree in Electrical Engineering was from the Agra University, India in 1957.

Q. Please describe your pertinent work experience.

A. I worked at the Arizona Corporation Commission from 1988 to 1998 as a Utilities Consultant, and have subsequently worked at the Commission as an Electric Utilities Engineer since June 2002. During this time period of over sixteen years, I conducted engineering evaluations of electric utility rate cases and financing cases, such as Arizona Public Service Company, Tucson Electric Company, Southwest Gas Company, Trico Electric Cooperative, Duncan Valley Electric Cooperative; Sulphur Springs Valley Electric Cooperative, Graham County Electric Cooperative, and Graham County Utilities, Inc., Gas Division. I inspected utility power plants including the Palo Verde Nuclear Generating Station. I was involved with the development of retail competition in Arizona and of DesertStar, an Independent System Operator ("ISO") for the desert southwest region. I was Chairman of the System Reliability Working Group, which evaluated the impact of competition on system reliability and recommended the establishment of the Arizona Independent System Administrator ("AISA") as an interim organization until commercial operation of DesertStar, which later evolved as WestConnect, a Regional Transmission Operator ("RTO"). Since rejoining the Commission, I have reviewed the utilities' load curtailment plans; coordinated with the Commission Consultants to hold six workshops to report on the second thru the fifth Biennial Transmission Assessments for Arizona. I have also worked on compliance of Certificates of Environmental Compatibility including Harquahala, Panda Gila River, Red Hawk, Northern Arizona Project, and Coolidge power plants. In 2004, I testified in the line siting cases of Tucson Electric Power Company's ("TEP") 138 kV Robert Bills-Wilmont Substation and Trico Electric Cooperative's 115 kV Sandario Project. In 2007 and 2008, I testified in the Palo Verde to North Gila 500 kV project, 138 kV Vail to Cienega project and the Coolidge Station project.

From July 2001 to June 2002, I had my own consulting engineering firm, named P. K. Bahl & Associates. During that time, I was involved with deregulation of the electric power industry and the formation of RTO's, addressing the planning, congestion management, business practices and market monitoring activities of the then Northwest RTO and the MidWest ISO.

From July 1998 to August 2000, I worked as Chief Engineer at the Residential Utility Consumer Office. During that time period, I performed many of the duties I performed at the Commission. I was also involved with the Distributed Generation Work Group that looked at the impact of development of distributed generation in Arizona on system reliability, and modifications of interconnection standards currently specified by the jurisdictional utilities. I was a member of the AISA Board of Directors from September 1999 until June 2000. I was involved in the deliberations of the Market Interface Committee of the North American Electric Reliability Council ("NERC"). I also published and presented a number of technical papers at national and international conferences regarding transmission issues and distributed generation during the last thirty years.

Prior to my employment with the Commission, I had worked as an electrical engineer with electric utilities and consulting firms in the transmission and generation planning areas for approximately thirty two years, including ten years' experience at the Punjab State Electricity Board ("PSEB") in India from 1960 to 1970. I worked as Executive Engineer at the PSEB from 1968 to 1970 prior to coming to the United States in 1970.

Q. As part of your assigned duties at the Commission, did you perform an analysis of the application that is the subject of this proceeding?

A. Yes, I did.

Q. Is your testimony herein based on that analysis?

A. Yes, it is.

PURPOSE OF TESTIMONY

Q. What is the purpose of your prefiled testimony?

A. The purpose of my testimony is to discuss Staff's engineering evaluation of Sulphur Springs Valley Electric Cooperative's ("SSVEC" or "Cooperative") system operations and planning, and to discuss Staff's review of SSVEC's Cost of Service Study ("COSS") for the bundled rate case, and present the results of this review.

ENGINEERING EVALUATION

Q. Would you please describe SSVEC's general utility background and potential load growth in its service territory?

A. Yes. The following provides SSVEC's electric system overview and customer and load growth projected by the Cooperative.

Utility Overview

SSVEC became a partial requirements member of Arizona Electric Power Cooperative ("AEPCO") on January 1, 2008. According to SSVEC, the Cooperative will have the need to secure up to 100 MW beyond its current level of supply of power from AEPCO, during peak load conditions. AEPCO's power is delivered to SSVEC through the transmission system of Southwest Transmission Cooperative, Inc. ("SWTC") and is measured at SWTC's wholesale delivery points at San Rafael 230 kV Substation, Kartchner 115 kV Substation, Apache Power Plant 115 kV Substation, and Red Tail 230 kV Substation. At year end 2008, SSVEC provided electric power to its members via 4,012 miles of energized lines, including 286 miles of sub-transmission lines, 3,008 miles of overhead distribution lines and 718 miles of underground distribution cables. Like other cooperatives in the state of Arizona, SSVEC's major customer base and consumption is residential load.

For the future generation needs, the Cooperative is evaluating participation in other planned generation projects in Arizona, including the Southwest Power Group's Bowie Plant and the generation resources planned by the Southwest Public Power Resource group ("SPPR") for its intermediate power needs.

The Cooperative's service territory is located within Western Area Power Administration's ("WAPA") Control Area[1]. A geographical layout of SSVEC's sub-transmission lines and present substations is attached as Exhibit 1.

Customer and Load Growth

SSVEC's total number of customers grew from 38,976 in 1998 to 50,365 in 2008. This is an average increase of 2.9% per year. Long-term growth projected by the Cooperative anticipates 52,708 customers in 2009, increasing at an average rate of 2.26% per year to 81,255 customers in 2033.

The Cooperative's retail load grew from approximately 96 MW in 1998 to 191.2 MW in 2008, which is an average increase of 7.2% per year. However, the Cooperative is projecting a load growth of only 3.37% per year for the next 24 years ending 2033 because of the current depressed economic conditions.

Q. Did Staff perform an engineering evaluation of SSVEC's electrical system?

A. Yes. On November 6 & 7, 2008, I visited the offices of SSVEC in Benson and Sierra Vista. There I met with the following people: Anselmo Torres Jr., Chief Operations & Engineering Officer; Ron Orozco, Engineering Manager; Pete Swiatek, Maintenance /Operations Supervisor; David Bryan, Engineer; Kirby Chapman, Chief Financial Officer; Al Smith, Technical Services Supervisor; David Bane, Key Accounts Manager; Ricardo Garcia, Construction Manager; Derek Sorely, Purchasing Manager; Kurt Towler, GIS Coordinator; and Bobby Bernal, Maintenace/Operations Supervisor designee.

---

[1] A Control Area monitors actual and scheduled transmission transactions to assure load and generation are balanced within its system and power flows are within the ratings of the transmission facilities.

Q. What issues were discussed with the SSVEC officials?

A. I discussed with the Cooperative officials the status and details of SSVEC's Sierra Vista transmission reliability (including SSVEC's efforts to improve service reliability in this area), Sonoita area reliability, wooden pole replacement schedule and the Cooperative's general maintenance practices. In addition, I toured various parts of the SSVEC system.

Q. What are the major capital improvements projects that SSVEC plans to cover in its Work Plan?

A. I discussed the details of SSVEC's Work Plan with Mr. Torres, Mr. Orozco, Mr. Swiatek and Mr. Bryan. The Cooperative explained the need and justification of various projects included in the Plan. These projects include installation of new underground cables, upgrading of distribution and tie lines, upgrading of certain 69 kV lines and construction of a 69 kV line to Sonoita and the new Sonoita Substation. The present distribution line to Sonoita has reached its capacity and needs to be built at a higher voltage to meet the load requirements in a reliable manner. New distribution feeders and tie lines would emanate from the Sonoita Substation with a feeder tie to the existing Huachuca Substation, which currently serves the area. New sub-transmission feeders would also include St. David to Cottonwood, Ramsey Substation to a new substation in Hereford, a short sub-transmission tie to the APS 69 kV system at Palominas, and Stewart switching station to Mortenson Substation. In addition, SSVEC has allocated monies to 69 kV sub-transmission upgrades to accommodate greater system loading, and to replace some of the old wooden poles with new concrete poles with under-build of 24.7 kV distribution feeders. Some of these concrete poles at an angle or end of the line are stand-alone poles without requirement of any guy wire. These projects are not site-specific at this time, but their need is known.

Q. Would you explain the Sonoita Project controversy?

A. Mr. Orozco made a power point presentation of the details of the Sonoita project, which is proposed to resolve significant capacity, reliability and power quality problems in the Sonoita/Elgin/Patagonia service area. SSVEC's proposal for a new substation to divide the existing 360-mile distribution feeder into multiple short feeders will resolve the current reliability issues. The 69 kV sub-transmission line to serve the substation is the most controversial part of the project. Although SSVEC's easement for the 69 kV line was procured more than a quarter of a century ago, residents of the area oppose the line due to its location on the San Ignacio del Babocomari Land Grant, a private property of scenic beauty, and on property within the residential area where SSVEC's substation property exists. The Cooperative continues to communicate with the citizens through public meetings and mailings, giving them a clear indication that the issue of this project is reliability and quality of service. SSVEC hopes to resolve this issue in the near future.

Q. What was the purpose of Staff's site visits?

A. The purpose of Staff's site visits was to inspect the operation and maintenance of the Cooperative's subtransmission and distribution lines and substations, and to see the construction of new upgraded poles and installation of fiber optic cable out of Kartchner Substation. Staff's purpose was also to inspect the installation of Automatic Meter Reading equipment the Cooperative's inventory yard to verify the purposeful procurement of equipmentyards

Q. Would you summarize your site visits with various SSVEC officials?

A. Yes. The following summarizes my site visits to the various substations and construction sites, and comments/conclusions and observations specific to each site.

<u>November 6, 2008</u>

San Rafael 230 kV Substation – David Bryan

- General overview of San Rafael Substation.
- General discussion on the Fifth Biennial Transmission Assessment Order under which San Rafael Substation should be looped with Kartchner Substation to improve long-term reliability in the Sierra Vista area.
- Voltages used on SSVEC system (69 kV, 7.2/12.47 kV, 14.4/24.9 kV, and on the Fort Huachuca 13.8 kV).
- SSVEC is moving forward with SWTC for a 2nd transformer, approximately 150 MVA in size, to be installed at the San Rafael Substation in 2010.

Kartchner Substation

Highway 90 Bypass69 kV Sub-Transmission Project – Messrs. Torres, Swiatek, Orozco, Bernal, Garcia, Jacobs

- Viewed four new 69 kV sub-transmission circuits on a dozen concrete poles with unguyed steel corner poles. The Cooperative is rebuilding this entire line to beyond the Bella Vista Tap.
- Several 69 kV circuits had new 12.4 kV distribution under-build.
- Watched crews adjust 69 kV gang operated air break switch.
- New sub-transmission line has fiber optic cable in the static wire.
- This project provides additional backup to SWTC's transmission facilities by providing additional sub-transmission path. This project will also provide additional backup paths for the forthcoming TEP and APS tie lines.

Sierra Vista Sub – Messrs. Swiatek, Orozco, Bernal, Garcia, Jacobs

- Viewed new 69 kV drop into substation.
- New 69 kV and lower voltage under-build.
- Viewed Automatic Meter Reading ("AMR") installation including injection pad transformer and discussed other major substation AMR components, such as Receiving Transformer Units ("RTU"), etc.
- Viewed new underground U3 and U7 1000 kCM new cable feeder getaways.
- Cooper Regulator controls installed.

Keating Sub –Messrs. Swiatek, Orozco, Bernal and Garcia

- SSVEC's 10 MVA Mobile Substation was in use.
- SSVEC's Mobile Regulator and Viper recloser trailer was in use.
- Supervisory Control and Data Acquisition ("SCADA") controls were operational and viewable.
- Use of PME (name brand) cabinets on feeders.
- Rebuild of the distribution T3 feeder and upcoming T2 feeder rebuild.

Tombstone Junction -- Messrs. Orozco and Swiatek

- SSVEC is working to keep this 69 kV switching station as an integral part of SSVEC's sub-transmission network.
- SSVEC replaced most of its very old breakers in 2008. This project provides additional backup to SWTC transmission facilities by upgrading a vital subtransmission path. This project will also provide additional backup for the forthcoming TEP and APS tie lines.

Tombstone Sub – Messrs. Orozco and Swiatek

- Viewed new substation with 10/12/14 MVA, 69/25 kV transformer.
- Substation has SEL (name brand) relays, and SCADA facilities.
- 4 underground getaways, 69 kV construction with 25 kV under-build, and new 25 kV distribution feeders.
- oil spill prevention swells, which are made of plastic coated Geotec fabric.
- detailed review of animal- and bird-proofing methods at the substation.

<u>November 7, 2008</u>

Substation Maintenance – Messrs. Smith and Bryan

- Discussed Substation maintenance and line recloser maintenance.
- Over $130,000 of maintenance equipment has been purchased over the last few years to ensure the Cooperative's key facilities are kept in shape. The equipment purchased includes:

  $40,000 Megger Power Factor Insulation Tester.

  $60,000 Doble Test Set.

  $20,000 Thermal Camera.

  $10,000 Current Transformer Tester.

  $3,000 Transformer Turns Ratio ("TTR") Tester.
- This equipment has identified problems in newly built substations, large customer distribution transformers, substation transformers, and other facilities prior to any facility failing.
- This equipment has kept outages from occurring and allowed the orderly and timely repair.
- Inspection forms are in separate PDF files.

Line Maintenance – Messrs. Swiatek, Bernal and Bryan

- Issues discussed included line patrol, cable injection, and tree trimming.
- SSVEC systemically patrols its facilities, and SSVEC personnel routinely inspect facilities as part of their daily travels.

Underground cable injection

- For older underground cables that were direct buried, SSVEC uses two companies that inject the cable with life-prolonging fluid. This prevents having to replace the cable, which is often in people's backyards, and ultimately saves money.
- Fluid injection is approximately $9/foot; cable replacement is $20 and up per foot.

Tree trimming

- SSVEC has contracted with Asplundh Tree Experts for all tree trimming services for the last 13 years.
- They are scheduled to trim trees in three different service areas, Willcox, Benson and Sierra Vista.
- One crew works full time on a regular rotation.
- A part-time crew is called in every 4th or 5th year depending on rain fall and high seasonal growth.

Purchasing – Messrs. Sorely and Bryan

Issues discussed included:

- New DOE efficiency standards for transformers.
- Purchasing working closely with Operations and Engineering to ensure sufficient but not excessive material on hand.

Bidding for material

- SSVEC receives bids or quotes for almost all items purchased.
- For line materials, five vendors are solicited, and each vendor typically returns two bids.
- Normally, ten bids are received on all routine line materials.
- Purchasing typically requests and receives at least three bids on major office equipment such as computers.

Sonoita Reliability Project– Messrs. Orozco, Swiatek, Garcia and Towler

- Kurt Towler showed a 3-dimensional view of four options considered for the final portion of the route.
- Ron Orozco presented an overview of the entire project and details on Babocomari Ranch easement issues.
- A complete package of information, including information from community meetings, was presented.
- A map showing the route in its entirety was included.
- SSVEC is scheduled to make a final selection on the route week of Nov 17.
- The Cooperative presented the new location for the substation.
- This new location is in response to community input and opposition to the previous site known as the Buchanan site.
- SSVEC has held four community meetings, sent six mass mailings to people in the area, and fielded public comment for nine months.

Benson Warehouse -- David Bryan

- Discussed general questions on equipment.
- Selectively inspected the inventory and did not find any material or equipment that was not used and useful.

Q. Describe the Fort Huachuca Distribution Electric Privatization project.

A. SSVEC acquired the Fort Huachuca Distribution Electric Privatization project in September 2004. A transition period was established for approximately 90 days while SSVEC hired personnel to support the Operation and Maintenance (O&M) and Renewals and Replacements (R&R) portions of the project. In January 2005, SSVEC began full-time operation of the Fort Huachuca 13.8 kV electric distribution system. TEP is still the supplier of electricity to the Fort Huachuca Substation.

The existing Fort Huachuca Substation is fed from the 13.8 kV tertiary tap on TEP's 138/46 kV, 50 MVA transformer. The transformer's main feed is TEP's 138 kV line (50 MVA of capacity) and the backup feed is TEP's 46 kV line (approximately 17 MVA of capacity). The 13.8 kV overhead bus work feeds four underground risers to two metal clad switchgears. Each switchgear is fed at each end by an underground feeder with a tie breaker in the middle. There are a total of 12 primary distribution circuits feeding the Fort's distribution system. Each switchgear has rack mounted capacitor banks that are controlled for unity power factor. There is approximately 65 miles of overhead primary distribution and approximately 45 miles of underground primary distribution. There are about 900 distribution transformers serving approximately 4,300 customers. SSVEC is in the process of metering all services on the Fort.

The new contract provided for Initial Capital Upgrades ("ICU") that would improve the electric distribution system. One of the major ICU projects was Greely Hall. This 100,000 square foot building had originally been a manufacturing plant. There were several indoor vaults that contained oil filled switches and transformers. The ICU funding allowed relocation and replacement of this indoor equipment with standard outdoor transformers, primary dead front switchgear and new service entrance switches. This project will be completed by the end of 2008. Another ICU project was to design a backup substation that could provide Fort Huachuca with power from the Kartchner Substation in case of an emergency. The design should be completed in January 2009 and Fort Huachuca will be asking Congress for funding to build the substation. The ICU projects are expected to continue for at least two more years.

In early January of 2005, SSVEC learned there would be other electrical distribution functions to perform on Fort Huachuca. The Corps of Engineers was replacing old housing with new housing units and SSVEC is responsible for the design and construction of the new distribution facilities. The Corps of Engineers provided funding to SSVEC for construction of the new facilities. SSVEC also learned there would be other Special Projects for electric distribution. These Special Projects were paid for by various government entities. The various types of projects include installing electric distribution facilities to serve new buildings, upgrading electric distribution facilities to serve load increases, and provide new street lighting. These Special Projects have required a full time SSVEC construction crew to be assigned to the Fort.

Q. What is Staff's view of SSVEC's system reliability?

A. The system is unable to sustain single contingency during summer peak load conditions since it is only served by two SWTC radial transmission lines into the Sierra Vista area, at the 230 kV San Rafael substation and 115 kV Kartchner Substation, both having 100 MVA capacity transformers,. In October of 2007, the Sierra Vista area suffered two total blackouts when the 115 kV line to Kartchner experienced an outage while the Butterfield-San Rafael 230 kV line was taken out of service for installing fiber optic cable on the line. These blackouts occurred one day apart. In addition, a short blackout occurred earlier that same month. SSVEC is currently working with the Cochise County Transmission Study group to determine the best technical solution for improved reliability in the area. SSVEC's sub-transmission system will likely be called upon to back-up SWTC's transmission system until a longer-term solution is identified. In addition, SSVEC engineering is moving forward with SWTC engineering to provide for a second and larger transformer (150 MVA) at the San Rafael Substation. The proposal is still being evaluated and must be approved by SSVEC and SWTC management.

Q. How does Staff assess SSVEC's quality of service in terms of customer outage hours?

A. SSVEC's outage hours per consumer per year varied between 1.10 in 2005 and 3.52 in 2007 for the 2004-2007 period, showing an average of 2.09 outage hours per consumer per year[2]. SSVEC's outage ratio is well below the Rural Utilities Service ("RUS") guidelines of 5 outage hours per consumer per year. This shows that, in general, the Cooperative is providing reliable service to its customers and responding to outages in a timely manner.

Q. At what level are SSVEC's overall system losses? Are they reasonable and acceptable?

A. SSVEC's annual system losses ranged between 5.60 percent in 2002 and 7.22 percent in 2006 in 2000-2007. These losses are well within the industry guidelines of 10 percent per year for rural electric cooperatives.

Q. What is SSVEC's wooden pole replacement program?

A. SSVEC has approximately 81,000 wooden poles, many of which are more than 45 years old. The Cooperative replaces these older wooden poles on a scheduled basis according to

[2] In October 2007, four SWTC transmission outages caused nearly 68,000 consumer-outage hours alone.

the Construction Work Plan. SSVEC replaced over 600 poles in 2008. SSVEC's pole replacement program has three major aspects to Risk Identification and Assessment:

1. Osmose Pole Testing: SSVEC contracts with Osmose to physically inspect and chemically test approximately 6,000 poles per year. Inspections are selected on the basis of last inspection year, age of poles, relative importance of line, and voltage.
2. Line Patrol: SSVEC inspects 15% of its lines every year for specific maintenance requirements.
3. Spot Maintenance and New Construction: As crews work near existing lines, poles are inspected and replaced as necessary. Any poles identified for immediate replacement are replaced by the Maintenance crews.

COST OF SERVICE STUDY

Q. What is the purpose of preparing a Cost of Service Study ("COSS")?

A. There are three steps to take in performing a COSS. 1) functionalization; 2) classification, and 3) allocation. First, the COSS enables us to determine the system's cost of service by classifying the utility's costs (investments and expenses) by function, such as customer-related, demand-related, and energy-related functions. Second, the study breaks down costs by customer classes to reflect, as closely as possible, the cost causation by respective customer classes. Third, the result of the COSS provides a benchmark for the revenues needed from each customer category by allocating the revenue requirement for each customer class.

Q. Is there a standard COSS model?

A. There is no standard methodology for designing a COSS, but it is generally advisable to follow a range of alternatives to identify which allocations are more reasonable than others. For that reason, the COSS should be used as a general guide only and is only one of many considerations in designing rates.

Q. What process was used by Staff in reviewing the SSVEC's COSS

A. First, I reviewed the model used by the Cooperative in developing various allocation factors in the bundled COSS. Second, I reviewed the Test Year ("TY 2007") rate base, revenues and expenses in the bundled rate case, adjusted by the Cooperative by its Pro Forma adjustments, and matched them with the appropriate schedules contained in the application. Third, I incorporated the changes in the COSS that Staff witness, Crystal Brown, had made in the revenue requirement.

Q. What model was used by SSVEC in developing its COSS and is Staff satisfied with the input data utilized in this model?

A. For conducting the COSS, SSVEC engaged the services of C. H. Guernsey & Company ("Consultants"), out of Oklahoma City, Oklahoma. The Consultants used their in-house model, named CoOPTIONS. The same model was used by the Consultants and was approved by the Commission in the last rate case filed by Trico Electric Cooperative (Docket No. E-01461A).

Q. What did Staff determine from its review of the Cost of Service Study?

A. SSVEC's COSS used appropriate methods to functionalize, classify and allocate costs. The weighting factors SSVEC used were reasonable. SSVEC appropriately used the "Sum of 12 Non-coincident Peaks ("NCP")[3]" to allocate demand charges to each of the customer classes. A 12-month demand allocation factor was developed using the monthly purchased demand values during the test year, as the system monthly total. The allocation

[3] **Non-coincident Peak** is the maximum demand experienced by SSVEC in a specified period of time, such as a month or a year, which occurs at a time other than the time when AEPCO experiences its peak.

of monthly demand responsibility was made to all of the classes with metered demand by applying the appropriate losses, Load Factors[4] and Coincidence Factors[5] to metered demand values for that class. After the allocation of Coincident Peak ("CP")[6] demand responsibility was made to the classes with metered demand, the remainder of the CP demand was assigned to the non-demand metered classes (such as Residential, General Service (1), and Time of Day Water Pumping) based on their respective kWh sales.

The COSS model appropriately calculated the components of the bundled case. Attached herewith as Exhibit 2 is the Cost of Service Study Schedules, showing Cost Allocation Summary - Staff Adjusted Rates (Schedule PB-G 1.0), and Summary of Components of Expenses (Schedule PB-M 1.0).

Q. Did the methods used by SSVEC comply with industry standards?

A. SSVEC used procedures and methodology that are generally accepted standards throughout the utility industry for its cost of service study. Allocation of invested capital and operating expenses were allocated to the respective customer classes on the basis of demand, energy and other customer related factors.

Q. Does Staff have a recommendation concerning SSVEC's Cost of Service Study?

A. Staff recommends the Commission accept SSVEC's Cost of Service Study in this case.

---

[4] **Load Factor** is calculated as the ratio of energy to demand for a set time frame. The load factor based on maximum demand will always be between 0 and 1.

[5] **Coincidence Factor** is the ratio of coincident demand to maximum demand. This will always be between 0 and 1 because coincident demand should always be less than or equal to maximum demand.

[6] **Coincident Peak** means the maximum system demand which occurs at the same time that AEPCO peak occurs every month. SSVEC is charged by AEPCO based on its peak coincident with AEPCO's peak.

CONCLUSIONS AND RECOMMENDATIONS

Q. Based upon your testimony, what are Staff's conclusions and recommendations regarding its engineering evaluation of SSVEC's electrical system and the COSS?

A. Staff's conclusions and recommendations are as follows:

CONCLUSIONS

Based on Staff's engineering inspection of SSVEC's electric system, and evaluation and analysis of SSVEC's Cost of Service study results, Staff concludes as follows:

4. That SSVEC:
    a. is operating and maintaining its electrical system properly,
    b. is carrying out system improvements, upgrades and new additions to meet the current and projected load of the Cooperative in an efficient and reliable manner,
    c. has an acceptable level of system losses consistent with the industry guidelines,
    d. is working with the Cochise County Transmission study group to implement the directions issued in the 5th BTA Order (Decision No. 70635),
    e. has a satisfactory record of service interruptions in the historic period between 2004 and 2007, showing an average of 2.09 outage hours per consumer per year,
    f. has evaluated numerous options regarding the Sonoita Reliability Project ("SRP") and its associated 69kV line to Sonoita. The proposed SRP will improve service reliability in Sonoita, Patagonia and Elgin service areas.
5. That SSVEC has used its COSS model for the bundled rate filing appropriately. The model used by SSVEC is consistent with what the Commission approved for use in another cooperative rate case.
6. That, based on the evaluation of the COSS model utilized by SSVEC, the results are satisfactory.

RECOMMENDATIONS

Based on the aforementioned conclusions, Staff recommends that:

1. SSVEC work with other entities, such as Arizona Public Service Company, Tucson Electric Company, and Southwest Transmission Cooperative to establish "continuity" of service, as ordered by the Commission in the fifth BTA in Decision No. 70635, in the Cochise County area including the Sierra Vista area.
2. SSVEC continue to upgrade its 69 kV sub-transmission and distribution system to improve system performance and reliability for its members.
3. SSVEC continue with its wooden pole replacement program.
4. Commission accept SSVEC's Cost of Service Study for use in this case.

Q. Does that conclude your testimony?

A. Yes, it does.

EXHIBIT 1

Geographical Layout of SSVEC's Present and Proposed System

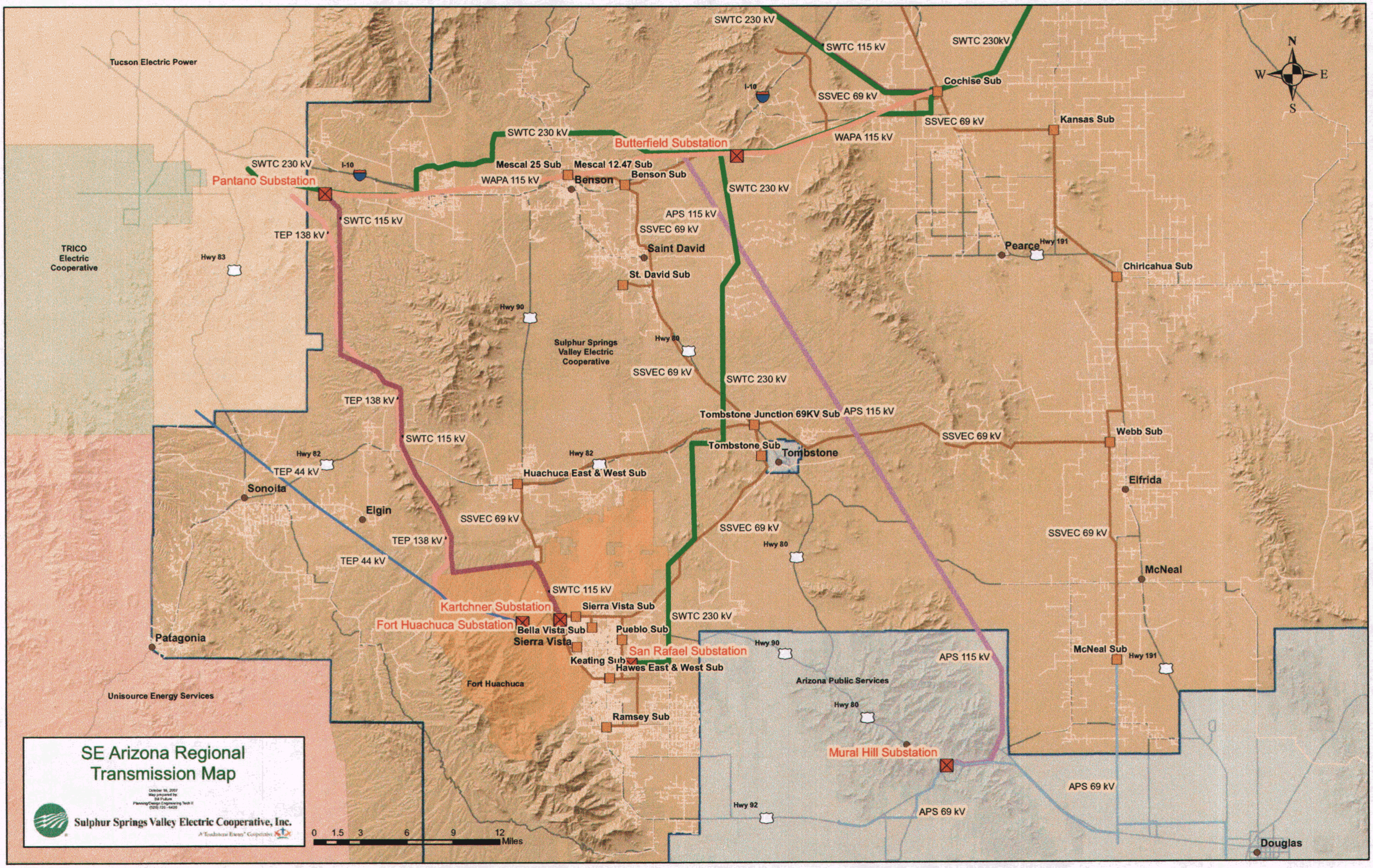

SE Arizona Regional Transmission Map
Sulphur Springs Valley Electric Cooperative, Inc.
0 1.5 3 6 9 12 Miles
Tucson Electric Power
TRICO Electric Cooperative
Unisource Energy Services
Arizona Public Services
Sulphur Springs Valley Electric Cooperative
Pantano Substation
Butterfield Substation
Kartchner Substation
Fort Huachuca Substation
San Rafael Substation
Mural Hill Substation
Mescal 25 Sub
Mescal 12.47 Sub
Benson Sub
Benson
Saint David
St. David Sub
Cochise Sub
Kansas Sub
Pearce
Chiricahua Sub
Webb Sub
Elfrida
McNeal
McNeal Sub
Douglas
Tombstone Junction 69KV Sub
Tombstone Sub
Tombstone
Huachuca East & West Sub
Sierra Vista Sub
Bella Vista Sub
Sierra Vista
Pueblo Sub
Keating Sub
Hawes East & West Sub
Ramsey Sub
Fort Huachuca
Sonoita
Elgin
Patagonia
SWTC 230 kV
SWTC 115 kV
SWTC 230kV
SSVEC 69 kV
WAPA 115 kV
APS 115 kV
APS 69 kV
TEP 138 kV
TEP 44 kV
I-10
Hwy 83
Hwy 90
Hwy 82
Hwy 80
Hwy 191
Hwy 92
N
S
E
W

EXHIBIT 2

Cost of Service Study Schedules

ARIZONA CORPORATION COMMISSION
SSVEC EXISTING RATES - Staff Adjusted
DOCKET NO. E-01575A-08-0328 - TY 12-31-07
Cost Allocation Summary

Account	Total	Residential	Gen Service	GS-TOU	RV Parks	Lighting
Rate Base	132,886,193	68,053,411	28,155,313	281,107	497,577	3,146,313
Operating Revenues	93,744,086	43,811,584	13,610,790	96,828	460,552	764,559
Operating Expenses	85,055,074	42,019,922	13,553,585	101,634	415,127	963,855
Return	8,689,012	1,791,662	57,204	-4,805	45,424	-199,296
Rate of Return	6.539 %	2.633 %	0.203 %	-1.710 %	9.129 %	-6.334 %
Relative ROR	1.000	0.403	0.031	-0.261	1.396	-0.969
Interest	7,106,255	3,782,902	1,463,408	14,020	25,173	153,507
Operating Margins	1,582,757	-1,991,240	-1,406,203	-18,826	20,251	-352,803
Margin as % Revenue	1.688 %	-4.545 %	-10.332 %	-19.443 %	4.397 %	-46.145 %
Operating TIER	1.223	0.474	0.039	-0.343	1.805	-1.298
Revenue Deficiencies						
Uniform ROR = 11.320000	6,353,705	5,911,984	3,129,976	36,626	10,900	555,459
Deficiency % Rev	6.778 %	13.494 %	22.996 %	37.827 %	2.367 %	72.651 %
Uniform % Mar = 7.928708	6,353,705	5,935,545	2,699,390	28,785	17,664	449,025
Deficiency % Rev	6.778 %	13.548 %	19.833 %	29.729 %	3.835 %	58.730 %

ARIZONA CORPORATION COMMISSION
SSVEC EXISTING RATES - Staff Adjusted
DOCKET NO. E-01575A-08-0328 - TY 12-31-07
Cost Allocation Summary

Account	Total	Large Power	LP-TOU	LP Industrial	Contracts	Ft Huachuca
Rate Base	132,886,193	12,958,769	635,012	2,023,134	2,476,865	-27,507
Operating Revenues	93,744,086	12,691,966	666,460	2,248,751	2,954,463	3,741,026
Operating Expenses	85,055,074	10,916,906	452,330	2,044,579	2,554,418	1,739,427
Return	8,689,012	1,775,059	214,130	204,171	400,044	2,001,598
Rate of Return	6.539 %	13.698 %	33.721 %	10.092 %	16.151 %	-7,276.685 %
Relative ROR	1.000	2.095	5.157	1.543	2.470	-1,112.866
Interest	7,106,255	657,058	33,893	103,884	122,173	10,337
Operating Margins	1,582,757	1,118,000	180,237	100,286	277,870	1,991,261
Margin as % Revenue	1.688 %	8.809 %	27.044 %	4.460 %	9.405 %	53.228 %
Operating TIER	1.223	2.702	6.318	1.965	3.274	193.633
Revenue Deficiencies						
Uniform ROR = 11.320000	6,353,705	-308,126	-142,247	24,847	-119,663	-2,004,711
Deficiency % Rev	6.778 %	-2.428 %	-21.344 %	1.105 %	-4.050 %	-53.587 %
Uniform % Mar = 7.928708	6,353,705	-121,309	-138,366	84,728	-47,376	-1,840,580
Deficiency % Rev	6.778 %	-0.956 %	-20.761 %	3.768 %	-1.604 %	-49.200 %

ARIZONA CORPORATION COMMISSION
SSVEC EXISTING RATES - Staff Adjusted
DOCKET NO. E-01575A-08-0328 - TY 12-31-07
Cost Allocation Summary

Account	Total	Irrigation	Irrig-Daily	Irrig-Weekly	Irrig-Large	Total Irrig
Rate Base	132,886,193	6,209,460	1,390,965	3,661,790	3,423,978	14,686,194
Operating Revenues	93,744,086	5,576,168	967,155	3,144,184	3,009,594	12,697,103
Operating Expenses	85,055,074	5,036,284	636,978	2,571,448	2,048,573	10,293,284
Return	8,689,012	539,883	330,177	572,736	961,021	2,403,818
Rate of Return	6.539 %	8.695 %	23.737 %	15.641 %	28.067 %	16.368 %
Relative ROR	1.000	1.330	3.630	2.392	4.293	2.503
Interest	7,106,255	313,571	69,647	184,882	171,794	739,895
Operating Margins	1,582,757	226,312	260,529	387,853	789,226	1,663,922
Margin as % Revenue	1.688 %	4.059 %	26.938 %	12.336 %	26.224 %	13.105 %
Operating TIER	1.223	1.722	4.741	3.098	5.594	3.249
Revenue Deficiencies						
Uniform ROR = 11.320000	6,353,705	163,027	-172,719	-158,222	-573,426	-741,341
Deficiency % Rev	6.778 %	2.924 %	-17.859 %	-5.032 %	-19.053 %	-5.839 %
Uniform % Mar = 7.928708	6,353,705	234,390	-199,679	-150,492	-598,020	-713,801
Deficiency % Rev	6.778 %	4.203 %	-20.646 %	-4.786 %	-19.870 %	-5.622 %

ARIZONA CORPORATION COMMISSION
SSVEC EXISTING RATES - Staff Adjusted
DOCKET NO. E-01575A-08-0328 - TY 12-31-07
Summary of Components of Expenses

Accounts	Total	Residential	Gen Service	GS-TOU	RV Parks	Lighting
Average Consumers	50,263	40,457	8,373	41	12	278
kWh Sold	799,860,156	353,377,736	107,754,871	836,583	4,675,120	3,990,174
Metered kW		0	310,468	0	14,030	0
Billing kW		0	365,412	1,189	14,932	0
Demand-PurPwr-Gen	**19,008,826**	**9,906,486**	**3,039,080**	**13,345**	**113,076**	**40,395**
Monthly Cost per Cons	31.52	20.41	30.25	27.12	785.25	12.11
Average Cost per kWh	0.023765	0.028034	0.028204	0.015952	0.024187	0.010124
Cost per Metered kW		0.00	9.79	0.00	8.06	0.00
Cost per Billing kW		0.00	8.32	11.22	7.57	0.00
Demand-PurPwr-Del	**10,709,971**	**5,611,529**	**1,721,487**	**7,559**	**64,052**	**22,882**
Monthly Cost per Cons	17.76	11.56	17.13	15.36	444.81	6.86
Average Cost per kWh	0.013390	0.015880	0.015976	0.009036	0.013701	0.005735
Cost per Metered kW		0.00	5.54	0.00	4.57	0.00
Cost per Billing kW		0.00	4.71	6.36	4.29	0.00
Energy-PurPwr-Gen	**26,120,592**	**11,535,947**	**3,517,637**	**27,310**	**152,618**	**130,258**
Monthly Cost per Cons	43.31	23.76	35.01	55.51	1,059.85	39.05
Average Cost per kWh	0.032656	0.032645	0.032645	0.032645	0.032645	0.032645
Cost per Metered kW		0.00	11.33	0.00	10.88	0.00
Cost per Billing kW		0.00	9.63	22.97	10.22	0.00
Energy-PurPwr-Del	**1,852,198**	**829,553**	**252,954**	**1,964**	**10,975**	**9,367**
Monthly Cost per Cons	3.07	1.71	2.52	3.99	76.21	2.81
Average Cost per kWh	0.002316	0.002347	0.002347	0.002348	0.002347	0.002347
Cost per Metered kW		0.00	0.81	0.00	0.78	0.00
Cost per Billing kW		0.00	0.69	1.65	0.73	0.00
Dist-Substations	**2,667,810**	**1,231,635**	**362,968**	**1,567**	**13,279**	**4,744**
Monthly Cost per Cons	4.42	2.54	3.61	3.19	92.21	1.42
Average Cost per kWh	0.003335	0.003485	0.003368	0.001873	0.002840	0.001189
Cost per Metered kW		0.00	1.17	0.00	0.95	0.00
Cost per Billing kW		0.00	0.99	1.32	0.89	0.00

ARIZONA CORPORATION COMMISSION
SSVEC EXISTING RATES - Staff Adjusted
DOCKET NO. E-01575A-08-0328 - TY 12-31-07
Summary of Components of Expenses

Accounts	Total	Residential	Gen Service	GS-TOU	RV Parks	Lighting
Average Consumers	50,263	40,457	8,373	41	12	278
kWh Sold	799,860,156	353,377,736	107,754,871	836,583	4,675,120	3,990,174
Metered kW		0	310,468	0	14,030	0
Billing kW		0	365,412	1,189	14,932	0
Dist-Backbone	**10,275,945**	**5,225,910**	**1,540,098**	**6,649**	**56,342**	**20,127**
Monthly Cost per Cons	17.04	10.76	15.33	13.51	391.26	6.03
Average Cost per kWh	0.012847	0.014788	0.014293	0.007948	0.012051	0.005044
Cost per Metered kW		0.00	4.96	0.00	4.02	0.00
Cost per Billing kW		0.00	4.21	5.59	3.77	0.00
Dist-Demand	**4,468,185**	**2,050,598**	**1,203,878**	**15,954**	**7,102**	**37,373**
Monthly Cost per Cons	7.41	4.22	11.98	32.43	49.32	11.20
Average Cost per kWh	0.005586	0.005803	0.011172	0.019070	0.001519	0.009366
Cost per Metered kW		0.00	3.88	0.00	0.51	0.00
Cost per Billing kW		0.00	3.29	13.42	0.48	0.00
Dmd- Trans Plant	**884,916**	**436,117**	**128,526**	**555**	**4,702**	**1,680**
Monthly Cost per Cons	1.47	0.90	1.28	1.13	32.65	0.50
Average Cost per kWh	0.001106	0.001234	0.001193	0.000663	0.001006	0.000421
Cost per Metered kW		0.00	0.41	0.00	0.34	0.00
Cost per Billing kW		0.00	0.35	0.47	0.31	0.00
Dist-Customer	**7,828,428**	**3,422,484**	**1,857,152**	**24,517**	**7,649**	**751,344**
Monthly Cost per Cons	12.98	7.05	18.48	49.83	53.12	225.22
Average Cost per kWh	0.009787	0.009685	0.017235	0.029306	0.001636	0.188299
Cost per Metered kW		0.00	5.98	0.00	0.55	0.00
Cost per Billing kW		0.00	5.08	20.62	0.51	0.00
Distr. Meter	**1,934,583**	**1,205,190**	**393,269**	**10,175**	**1,191**	**0**
Monthly Cost per Cons	3.21	2.48	3.91	20.68	8.27	0.00
Average Cost per kWh	0.002419	0.003410	0.003650	0.012163	0.000255	0.000000
Cost per Metered kW		0.00	1.27	0.00	0.08	0.00
Cost per Billing kW		0.00	1.08	8.56	0.08	0.00

ARIZONA CORPORATION COMMISSION
SSVEC EXISTING RATES - Staff Adjusted
DOCKET NO. E-01575A-08-0328 - TY 12-31-07
Summary of Components of Expenses

Accounts	Total	Residential	Gen Service	GS-TOU	RV Parks	Lighting
Average Consumers	50,263	40,457	8,373	41	12	278
kWh Sold	799,860,156	353,377,736	107,754,871	836,583	4,675,120	3,990,174
Metered kW		0	310,468	0	14,030	0
Billing kW		0	365,412	1,189	14,932	0
Meter-Reading	**683,171**	**519,064**	**133,763**	**1,315**	**308**	**0**
Monthly Cost per Cons	1.13	1.07	1.33	2.67	2.14	0.00
Average Cost per kWh	0.000854	0.001469	0.001241	0.001572	0.000066	0.000000
Cost per Metered kW		0.00	0.43	0.00	0.02	0.00
Cost per Billing kW		0.00	0.37	1.11	0.02	0.00
Customer Records	**2,943,912**	**2,139,618**	**442,816**	**2,168**	**635**	**79,541**
Monthly Cost per Cons	4.88	4.41	4.41	4.41	4.41	23.84
Average Cost per kWh	0.003681	0.006055	0.004109	0.002592	0.000136	0.019934
Cost per Metered kW		0.00	1.43	0.00	0.05	0.00
Cost per Billing kW		0.00	1.21	1.82	0.04	0.00
Customer Service	**1,152,088**	**931,616**	**188,253**	**922**	**270**	**6,250**
Monthly Cost per Cons	1.91	1.92	1.87	1.87	1.87	1.87
Average Cost per kWh	0.001440	0.002636	0.001747	0.001102	0.000058	0.001566
Cost per Metered kW		0.00	0.61	0.00	0.02	0.00
Cost per Billing kW		0.00	0.52	0.78	0.02	0.00
Revenue	**1,630,704**	**757,076**	**235,112**	**1,655**	**8,103**	**13,402**
Monthly Cost per Cons	2.70	1.56	2.34	3.36	56.27	4.02
Average Cost per kWh	0.002039	0.002142	0.002182	0.001978	0.001733	0.003359
Cost per Metered kW		0.00	0.76	0.00	0.58	0.00
Cost per Billing kW		0.00	0.64	1.39	0.54	0.00
Total Expenses	92,161,329	45,802,825	15,016,993	115,654	440,300	1,117,363
Monthly Cost per Cons	152.80	94.34	149.46	235.07	3,057.64	334.94
Average Cost per kWh	0.115222	0.129614	0.139363	0.138247	0.094180	0.280029
Cost per Metered kW		0.00	48.37	0.00	31.38	0.00
Cost per Billing kW		0.00	41.10	97.27	29.49	0.00

ARIZONA CORPORATION COMMISSION
SSVEC EXISTING RATES - Staff Adjusted
DOCKET NO. E-01575A-08-0328 - TY 12-31-07
Summary of Components of Expenses

Accounts	Total	Residential	Gen Service	GS-TOU	RV Parks	Lighting
Average Consumers	50,263	40,457	8,373	41	12	278
kWh Sold	799,860,156	353,377,736	107,754,871	836,583	4,675,120	3,990,174
Metered kW		0	310,468	0	14,030	0
Billing kW		0	365,412	1,189	14,932	0
System Demand	**18,296,857**	**8,944,261**	**3,235,470**	**24,725**	**81,424**	**63,924**
Monthly Cost per Cons	30.34	18.42	32.20	50.25	565.44	19.16
Average Cost per kWh	0.022875	0.025311	0.030026	0.029555	0.017416	0.016020
Cost per Metered kW		0.00	10.42	0.00	5.80	0.00
Cost per Billing kW		0.00	8.85	20.79	5.45	0.00
Total Customer	**16,172,885**	**8,975,050**	**3,250,365**	**40,752**	**18,155**	**850,537**
Monthly Cost per Cons	26.81	18.49	32.35	82.83	126.08	254.96
Average Cost per kWh	0.020220	0.025398	0.030164	0.048712	0.003883	0.213158
Cost per Metered kW		0.00	10.47	0.00	1.29	0.00
Cost per Billing kW		0.00	8.90	34.27	1.22	0.00
Pur Pwr-Demand	**29,718,797**	**15,518,015**	**4,760,567**	**20,904**	**177,128**	**63,277**
Monthly Cost per Cons	49.27	31.96	47.38	42.49	1,230.06	18.97
Average Cost per kWh	0.037155	0.043913	0.044180	0.024987	0.037887	0.015858
Cost per Metered kW		0.00	15.33	0.00	12.62	0.00
Cost per Billing kW		0.00	13.03	17.58	11.86	0.00
Pur Pwr Energy/Fuel	**27,972,790**	**12,365,500**	**3,770,591**	**29,274**	**163,593**	**139,625**
Monthly Cost per Cons	46.38	25.47	37.53	59.50	1,136.06	41.85
Average Cost per kWh	0.034972	0.034992	0.034992	0.034992	0.034992	0.034992
Cost per Metered kW		0.00	12.14	0.00	11.66	0.00
Cost per Billing kW		0.00	10.32	24.62	10.96	0.00
Total Expenses	92,161,329	45,802,825	15,016,993	115,654	440,300	1,117,363
Monthly Cost per Cons	152.80	94.34	149.46	235.07	3,057.64	334.94
Average Cost per kWh	0.115222	0.129614	0.139363	0.138247	0.094180	0.280029
Cost per Metered kW		0.00	48.37	0.00	31.38	0.00
Cost per Billing kW		0.00	41.10	97.27	29.49	0.00

ARIZONA CORPORATION COMMISSION
SSVEC EXISTING RATES - Staff Adjusted
DOCKET NO. E-01575A-08-0328 - TY 12-31-07
Summary of Components of Expenses

Accounts	Total	Large Power	LP-TOU	LP Industrial	Contracts	Ft Huachuca
Average Consumers	50,263	335	38	8	2	1
kWh Sold	799,860,156	125,201,348	8,528,086	25,031,391	37,890,000	0
Metered kW		393,575	44,821	58,540	109,039	0
Billing kW		456,679	51,802	62,207	109,083	0
Demand-PurPwr-Gen	**19,008,826**	**2,882,089**	**26,951**	**552,522**	**550,768**	**0**
Monthly Cost per Cons	31.52	716.94	59.10	5,755.43	22,948.68	0.00
Average Cost per kWh	0.023765	0.023020	0.003160	0.022073	0.014536	0.000000
Cost per Metered kW		7.32	0.60	9.44	5.05	0.00
Cost per Billing kW		6.31	0.52	8.88	5.05	0.00
Demand-PurPwr-Del	**10,709,971**	**1,632,559**	**15,266**	**312,976**	**254,404**	**0**
Monthly Cost per Cons	17.76	406.11	33.48	3,260.16	10,600.15	0.00
Average Cost per kWh	0.013390	0.013039	0.001790	0.012503	0.006714	0.000000
Cost per Metered kW		4.15	0.34	5.35	2.33	0.00
Cost per Billing kW		3.57	0.29	5.03	2.33	0.00
Energy-PurPwr-Gen	**26,120,592**	**4,087,174**	**278,398**	**813,130**	**1,250,239**	**0**
Monthly Cost per Cons	43.31	1,016.71	610.52	8,470.11	52,093.28	0.00
Average Cost per kWh	0.032656	0.032645	0.032645	0.032484	0.032997	0.000000
Cost per Metered kW		10.38	6.21	13.89	11.47	0.00
Cost per Billing kW		8.95	5.37	13.07	11.46	0.00
Energy-PurPwr-Del	**1,852,198**	**293,910**	**20,020**	**58,472**	**63,765**	**0**
Monthly Cost per Cons	3.07	73.11	43.90	609.09	2,656.87	0.00
Average Cost per kWh	0.002316	0.002347	0.002347	0.002336	0.001683	0.000000
Cost per Metered kW		0.75	0.45	1.00	0.58	0.00
Cost per Billing kW		0.64	0.39	0.94	0.58	0.00
Dist-Substations	**2,667,810**	**338,443**	**32,859**	**59,715**	**290,829**	**14,632**
Monthly Cost per Cons	4.42	84.19	72.06	622.03	12,117.89	1,219.37
Average Cost per kWh	0.003335	0.002703	0.003853	0.002386	0.007676	0.000000
Cost per Metered kW		0.86	0.73	1.02	2.67	0.00
Cost per Billing kW		0.74	0.63	0.96	2.67	0.00

ARIZONA CORPORATION COMMISSION
SSVEC EXISTING RATES - Staff Adjusted
DOCKET NO. E-01575A-08-0328 - TY 12-31-07
Summary of Components of Expenses

Accounts	Total	Large Power	LP-TOU	LP Industrial	Contracts	Ft Huachuca
Average Consumers	50,263	335	38	8	2	1
kWh Sold	799,860,156	125,201,348	8,528,086	25,031,391	37,890,000	0
Metered kW		393,575	44,821	58,540	109,039	0
Billing kW		456,679	51,802	62,207	109,083	0
Dist-Backbone	**10,275,945**	**1,436,035**	**0**	**253,376**	**134,512**	**257,255**
Monthly Cost per Cons	17.04	357.22	0.00	2,639.33	5,604.66	21,437.88
Average Cost per kWh	0.012847	0.011470	0.000000	0.010122	0.003550	0.000000
Cost per Metered kW		3.65	0.00	4.33	1.23	0.00
Cost per Billing kW		3.14	0.00	4.07	1.23	0.00
Dist-Demand	**4,468,185**	**231,181**	**21,916**	**15,092**	**14,982**	**469,874**
Monthly Cost per Cons	7.41	57.51	48.06	157.21	624.26	39,156.18
Average Cost per kWh	0.005586	0.001846	0.002570	0.000603	0.000395	0.000000
Cost per Metered kW		0.59	0.49	0.26	0.14	0.00
Cost per Billing kW		0.51	0.42	0.24	0.14	0.00
Dmd- Trans Plant	**884,916**	**119,841**	**11,635**	**33,134**	**36,428**	**0**
Monthly Cost per Cons	1.47	29.81	25.52	345.15	1,517.84	0.00
Average Cost per kWh	0.001106	0.000957	0.001364	0.001324	0.000961	0.000000
Cost per Metered kW		0.30	0.26	0.57	0.33	0.00
Cost per Billing kW		0.26	0.22	0.53	0.33	0.00
Dist-Customer	**7,828,428**	**262,529**	**25,647**	**8,942**	**25,490**	**760,314**
Monthly Cost per Cons	12.98	65.31	56.24	93.14	1,062.09	63,359.47
Average Cost per kWh	0.009787	0.002097	0.003007	0.000357	0.000673	0.000000
Cost per Metered kW		0.67	0.57	0.15	0.23	0.00
Cost per Billing kW		0.57	0.50	0.14	0.23	0.00
Distr. Meter	**1,934,583**	**33,256**	**37,723**	**695**	**137**	**181,572**
Monthly Cost per Cons	3.21	8.27	82.73	7.24	5.70	15,131.02
Average Cost per kWh	0.002419	0.000266	0.004423	0.000028	0.000004	0.000000
Cost per Metered kW		0.08	0.84	0.01	0.00	0.00
Cost per Billing kW		0.07	0.73	0.01	0.00	0.00

ARIZONA CORPORATION COMMISSION
SSVEC EXISTING RATES - Staff Adjusted
DOCKET NO. E-01575A-08-0328 - TY 12-31-07
Summary of Components of Expenses

Accounts	Total	Large Power	LP-TOU	LP Industrial	Contracts	Ft Huachuca
Average Consumers	50,263	335	38	8	2	1
kWh Sold	799,860,156	125,201,348	8,528,086	25,031,391	37,890,000	0
Metered kW		393,575	44,821	58,540	109,039	0
Billing kW		456,679	51,802	62,207	109,083	0
Meter-Reading	**683,171**	**8,594**	**1,219**	**205**	**257**	**0**
Monthly Cost per Cons	1.13	2.14	2.67	2.14	10.69	0.00
Average Cost per kWh	0.000854	0.000069	0.000143	0.000008	0.000007	0.000000
Cost per Metered kW		0.02	0.03	0.00	0.00	0.00
Cost per Billing kW		0.02	0.02	0.00	0.00	0.00
Customer Records	**2,943,912**	**17,717**	**2,010**	**423**	**2,644**	**0**
Monthly Cost per Cons	4.88	4.41	4.41	4.41	110.18	0.00
Average Cost per kWh	0.003681	0.000142	0.000236	0.000017	0.000070	0.000000
Cost per Metered kW		0.05	0.04	0.01	0.02	0.00
Cost per Billing kW		0.04	0.04	0.01	0.02	0.00
Customer Service	**1,152,088**	**7,532**	**854**	**180**	**45**	**0**
Monthly Cost per Cons	1.91	1.87	1.87	1.87	1.87	0.00
Average Cost per kWh	0.001440	0.000060	0.000100	0.000007	0.000001	0.000000
Cost per Metered kW		0.02	0.02	0.00	0.00	0.00
Cost per Billing kW		0.02	0.02	0.00	0.00	0.00
Revenue	**1,630,704**	**223,107**	**11,726**	**39,602**	**52,093**	**66,118**
Monthly Cost per Cons	2.70	55.50	25.71	412.52	2,170.54	5,509.84
Average Cost per kWh	0.002039	0.001782	0.001375	0.001582	0.001375	0.000000
Cost per Metered kW		0.57	0.26	0.68	0.48	0.00
Cost per Billing kW		0.49	0.23	0.64	0.48	0.00
Total Expenses	92,161,329	11,573,965	486,223	2,148,464	2,676,592	1,749,764
Monthly Cost per Cons	152.80	2,879.10	1,066.28	22,379.84	111,524.69	145,813.75
Average Cost per kWh	0.115222	0.092443	0.057014	0.085831	0.070641	0.000000
Cost per Metered kW		29.41	10.85	36.70	24.55	0.00
Cost per Billing kW		25.34	9.39	34.54	24.54	0.00

ARIZONA CORPORATION COMMISSION
SSVEC EXISTING RATES - Staff Adjusted
DOCKET NO. E-01575A-08-0328 - TY 12-31-07
Summary of Components of Expenses

Accounts	Total	Large Power	LP-TOU	LP Industrial	Contracts	Ft Huachuca
Average Consumers	50,263	335	38	8	2	1
kWh Sold	799,860,156	125,201,348	8,528,086	25,031,391	37,890,000	0
Metered kW		393,575	44,821	58,540	109,039	0
Billing kW		456,679	51,802	62,207	109,083	0
System Demand	**18,296,857**	**2,125,499**	**66,410**	**361,317**	**476,751**	**741,761**
Monthly Cost per Cons	30.34	528.73	145.64	3,763.72	19,864.64	61,813.42
Average Cost per kWh	0.022875	0.016977	0.007787	0.014435	0.012583	0.000000
Cost per Metered kW		5.40	1.48	6.17	4.37	0.00
Cost per Billing kW		4.65	1.28	5.81	4.37	0.00
Total Customer	**16,172,885**	**552,735**	**79,179**	**50,047**	**80,666**	**1,008,004**
Monthly Cost per Cons	26.81	137.50	173.64	521.32	3,361.07	84,000.33
Average Cost per kWh	0.020220	0.004415	0.009284	0.001999	0.002129	0.000000
Cost per Metered kW		1.40	1.77	0.85	0.74	0.00
Cost per Billing kW		1.21	1.53	0.80	0.74	0.00
Pur Pwr-Demand	**29,718,797**	**4,514,648**	**42,217**	**865,497**	**805,172**	**0**
Monthly Cost per Cons	49.27	1,123.05	92.58	9,015.60	33,548.83	0.00
Average Cost per kWh	0.037155	0.036059	0.004950	0.034576	0.021250	0.000000
Cost per Metered kW		11.47	0.94	14.78	7.38	0.00
Cost per Billing kW		9.89	0.81	13.91	7.38	0.00
Pur Pwr Energy/Fuel	**27,972,790**	**4,381,084**	**298,417**	**871,603**	**1,314,003**	**0**
Monthly Cost per Cons	46.38	1,089.82	654.42	9,079.20	54,750.15	0.00
Average Cost per kWh	0.034972	0.034992	0.034992	0.034820	0.034679	0.000000
Cost per Metered kW		11.13	6.66	14.89	12.05	0.00
Cost per Billing kW		9.59	5.76	14.01	12.05	0.00
Total Expenses	92,161,329	11,573,965	486,223	2,148,464	2,676,592	1,749,764
Monthly Cost per Cons	152.80	2,879.10	1,066.28	22,379.84	111,524.69	145,813.75
Average Cost per kWh	0.115222	0.092443	0.057014	0.085831	0.070641	0.000000
Cost per Metered kW		29.41	10.85	36.70	24.55	0.00
Cost per Billing kW		25.34	9.39	34.54	24.54	0.00

ARIZONA CORPORATION COMMISSION
SSVEC EXISTING RATES - Staff Adjusted
DOCKET NO. E-01575A-08-0328 - TY 12-31-07
Summary of Components of Expenses

Accounts	Total	Irrigation	Irrig-Daily	Irrig-Weekly	Irrig-Large	Total Irrig
Average Consumers	50,263	304	73	220	122	719
kWh Sold	799,860,156	54,045,765	10,581,835	32,780,060	35,167,187	132,574,847
Metered kW		225,515	38,710	119,961	106,805	490,991
Billing kW		233,576	55,568	163,086	0	452,230
Demand-PurPwr-Gen	**19,008,826**	**1,327,577**	**18,916**	**476,831**	**60,792**	**1,884,115**
Monthly Cost per Cons	31.52	363.92	21.59	180.62	41.52	218.37
Average Cost per kWh	0.023765	0.024564	0.001788	0.014546	0.001729	0.014212
Cost per Metered kW		5.89	0.49	3.97	0.57	3.84
Cost per Billing kW		5.68	0.34	2.92	0.00	4.17
Demand-PurPwr-Del	**10,709,971**	**752,006**	**10,715**	**270,101**	**34,435**	**1,067,257**
Monthly Cost per Cons	17.76	206.14	12.23	102.31	23.52	123.70
Average Cost per kWh	0.013390	0.013914	0.001013	0.008240	0.000979	0.008050
Cost per Metered kW		3.33	0.28	2.25	0.32	2.17
Cost per Billing kW		3.22	0.19	1.66	0.00	2.36
Energy-PurPwr-Gen	**26,120,592**	**1,764,314**	**345,442**	**1,070,099**	**1,148,026**	**4,327,880**
Monthly Cost per Cons	43.31	483.64	394.34	405.34	784.17	501.61
Average Cost per kWh	0.032656	0.032645	0.032645	0.032645	0.032645	0.032645
Cost per Metered kW		7.82	8.92	8.92	10.75	8.81
Cost per Billing kW		7.55	6.22	6.56	0.00	9.57
Energy-PurPwr-Del	**1,852,198**	**126,872**	**24,841**	**76,951**	**82,555**	**311,219**
Monthly Cost per Cons	3.07	34.78	28.36	29.15	56.39	36.07
Average Cost per kWh	0.002316	0.002347	0.002347	0.002347	0.002347	0.002347
Cost per Metered kW		0.56	0.64	0.64	0.77	0.63
Cost per Billing kW		0.54	0.45	0.47	0.00	0.69
Dist-Substations	**2,667,810**	**140,225**	**24,504**	**77,542**	**74,869**	**317,139**
Monthly Cost per Cons	4.42	38.44	27.97	29.37	51.14	36.76
Average Cost per kWh	0.003335	0.002595	0.002316	0.002366	0.002129	0.002392
Cost per Metered kW		0.62	0.63	0.65	0.70	0.65
Cost per Billing kW		0.60	0.44	0.48	0.00	0.70

ARIZONA CORPORATION COMMISSION
SSVEC EXISTING RATES - Staff Adjusted
DOCKET NO. E-01575A-08-0328 - TY 12-31-07
Summary of Components of Expenses

Accounts	Total	Irrigation	Irrig-Daily	Irrig-Weekly	Irrig-Large	Total Irrig
Average Consumers	50,263	304	73	220	122	719
kWh Sold	799,860,156	54,045,765	10,581,835	32,780,060	35,167,187	132,574,847
Metered kW		225,515	38,710	119,961	106,805	490,991
Billing kW		233,576	55,568	163,086	0	452,230
Dist-Backbone	**10,275,945**	**594,982**	**103,970**	**329,014**	**317,674**	**1,345,642**
Monthly Cost per Cons	17.04	163.10	118.69	124.63	216.99	155.96
Average Cost per kWh	0.012847	0.011009	0.009825	0.010037	0.009033	0.010150
Cost per Metered kW		2.64	2.69	2.74	2.97	2.74
Cost per Billing kW		2.55	1.87	2.02	0.00	2.98
Dist-Demand	**4,468,185**	**160,080**	**46,913**	**107,003**	**86,239**	**400,236**
Monthly Cost per Cons	7.41	43.88	53.55	40.53	58.91	46.39
Average Cost per kWh	0.005586	0.002962	0.004433	0.003264	0.002452	0.003019
Cost per Metered kW		0.71	1.21	0.89	0.81	0.82
Cost per Billing kW		0.69	0.84	0.66	0.00	0.89
Dmd- Trans Plant	**884,916**	**49,653**	**8,677**	**27,457**	**26,511**	**112,298**
Monthly Cost per Cons	1.47	13.61	9.90	10.40	18.11	13.02
Average Cost per kWh	0.001106	0.000919	0.000820	0.000838	0.000754	0.000847
Cost per Metered kW		0.22	0.22	0.23	0.25	0.23
Cost per Billing kW		0.21	0.16	0.17	0.00	0.25
Dist-Customer	**7,828,428**	**211,974**	**91,088**	**222,176**	**157,123**	**682,360**
Monthly Cost per Cons	12.98	58.11	103.98	84.16	107.32	79.09
Average Cost per kWh	0.009787	0.003922	0.008608	0.006778	0.004468	0.005147
Cost per Metered kW		0.94	2.35	1.85	1.47	1.39
Cost per Billing kW		0.91	1.64	1.36	0.00	1.51
Distr. Meter	**1,934,583**	**30,178**	**7,247**	**21,839**	**12,111**	**71,375**
Monthly Cost per Cons	3.21	8.27	8.27	8.27	8.27	8.27
Average Cost per kWh	0.002419	0.000558	0.000685	0.000666	0.000344	0.000538
Cost per Metered kW		0.13	0.19	0.18	0.11	0.15
Cost per Billing kW		0.13	0.13	0.13	0.00	0.16

ARIZONA CORPORATION COMMISSION
SSVEC EXISTING RATES - Staff Adjusted
DOCKET NO. E-01575A-08-0328 - TY 12-31-07
Summary of Components of Expenses

Accounts	Total	Irrigation	Irrig-Daily	Irrig-Weekly	Irrig-Large	Total Irrig
Average Consumers	50,263	304	73	220	122	719
kWh Sold	799,860,156	54,045,765	10,581,835	32,780,060	35,167,187	132,574,847
Metered kW		225,515	38,710	119,961	106,805	490,991
Billing kW		233,576	55,568	163,086	0	452,230
Meter-Reading	**683,171**	**7,799**	**1,873**	**5,644**	**3,130**	**18,446**
Monthly Cost per Cons	1.13	2.14	2.14	2.14	2.14	2.14
Average Cost per kWh	0.000854	0.000144	0.000177	0.000172	0.000089	0.000139
Cost per Metered kW		0.03	0.05	0.05	0.03	0.04
Cost per Billing kW		0.03	0.03	0.03	0.00	0.04
Customer Records	**2,943,912**	**79,541**	**3,861**	**11,635**	**161,303**	**256,340**
Monthly Cost per Cons	4.88	21.80	4.41	4.41	110.18	29.71
Average Cost per kWh	0.003681	0.001472	0.000365	0.000355	0.004587	0.001934
Cost per Metered kW		0.35	0.10	0.10	1.51	0.52
Cost per Billing kW		0.34	0.07	0.07	0.00	0.57
Customer Service	**1,152,088**	**6,835**	**1,641**	**4,946**	**2,743**	**16,166**
Monthly Cost per Cons	1.91	1.87	1.87	1.87	1.87	1.87
Average Cost per kWh	0.001440	0.000126	0.000155	0.000151	0.000078	0.000122
Cost per Metered kW		0.03	0.04	0.04	0.03	0.03
Cost per Billing kW		0.03	0.03	0.03	0.00	0.04
Revenue	**1,630,704**	**97,821**	**16,938**	**55,093**	**52,857**	**222,709**
Monthly Cost per Cons	2.70	26.81	19.34	20.87	36.10	25.81
Average Cost per kWh	0.002039	0.001810	0.001601	0.001681	0.001503	0.001680
Cost per Metered kW		0.43	0.44	0.46	0.49	0.45
Cost per Billing kW		0.42	0.30	0.34	0.00	0.49
Total Expenses	92,161,329	5,349,856	706,625	2,756,331	2,220,368	11,033,180
Monthly Cost per Cons	152.80	1,466.52	806.65	1,044.06	1,516.64	1,278.76
Average Cost per kWh	0.115222	0.098988	0.066777	0.084086	0.063137	0.083222
Cost per Metered kW		23.72	18.25	22.98	20.79	22.47
Cost per Billing kW		22.90	12.72	16.90	0.00	24.40

ARIZONA CORPORATION COMMISSION
SSVEC EXISTING RATES - Staff Adjusted
DOCKET NO. E-01575A-08-0328 - TY 12-31-07
Summary of Components of Expenses

Accounts	Total	Irrigation	Irrig-Daily	Irrig-Weekly	Irrig-Large	Total Irrig
Average Consumers	50,263	304	73	220	122	719
kWh Sold	799,860,156	54,045,765	10,581,835	32,780,060	35,167,187	132,574,847
Metered kW		225,515	38,710	119,961	106,805	490,991
Billing kW		233,576	55,568	163,086	0	452,230
System Demand	**18,296,857**	**944,940**	**184,064**	**541,017**	**505,294**	**2,175,314**
Monthly Cost per Cons	30.34	259.03	210.12	204.93	345.15	252.12
Average Cost per kWh	0.022875	0.017484	0.017394	0.016504	0.014368	0.016408
Cost per Metered kW		4.19	4.75	4.51	4.73	4.43
Cost per Billing kW		4.05	3.31	3.32	0.00	4.81
Total Customer	**16,172,885**	**434,148**	**122,647**	**321,334**	**389,267**	**1,267,395**
Monthly Cost per Cons	26.81	119.01	140.01	121.72	265.89	146.89
Average Cost per kWh	0.020220	0.008033	0.011590	0.009803	0.011069	0.009560
Cost per Metered kW		1.93	3.17	2.68	3.64	2.58
Cost per Billing kW		1.86	2.21	1.97	0.00	2.80
Pur Pwr-Demand	**29,718,797**	**2,079,582**	**29,632**	**746,931**	**95,227**	**2,951,372**
Monthly Cost per Cons	49.27	570.06	33.83	282.93	65.05	342.07
Average Cost per kWh	0.037155	0.038478	0.002800	0.022786	0.002708	0.022262
Cost per Metered kW		9.22	0.77	6.23	0.89	6.01
Cost per Billing kW		8.90	0.53	4.58	0.00	6.53
Pur Pwr Energy/Fuel	**27,972,790**	**1,891,186**	**370,283**	**1,147,050**	**1,230,581**	**4,639,099**
Monthly Cost per Cons	46.38	518.42	422.70	434.49	840.56	537.68
Average Cost per kWh	0.034972	0.034992	0.034992	0.034992	0.034992	0.034992
Cost per Metered kW		8.39	9.57	9.56	11.52	9.45
Cost per Billing kW		8.10	6.66	7.03	0.00	10.26
Total Expenses	92,161,329	5,349,856	706,625	2,756,331	2,220,368	11,033,180
Monthly Cost per Cons	152.80	1,466.52	806.65	1,044.06	1,516.64	1,278.76
Average Cost per kWh	0.115222	0.098988	0.066777	0.084086	0.063137	0.083222
Cost per Metered kW		23.72	18.25	22.98	20.79	22.47
Cost per Billing kW		22.90	12.72	16.90	0.00	24.40

EXHIBIT
S-6
admitted

BEFORE THE ARIZONA CORPORATION COMMISSION

KRISTIN K. MAYES
Chairman
GARY PIERCE
Commissioner
SANDRA D. KENNEDY
Commissioner
PAUL NEWMAN
Commissioner
BOB STUMP
Commissioner

IN THE MATTER OF THE APPLICATION OF SULPHUR SPRINGS VALLEY ELECTRIC COOPERATIVE, INC. FOR A HEARING TO DETERMINE THE FAIR VALUE OF ITS PROPERTY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RETURN THEREON, TO APPROVE RATES DESIGNED TO DEVELOP SUCH RETURN AND FOR RELATED APPROVALS.	DOCKET NO. E-01575A-08-0328

DIRECT

TESTIMONY

OF

CRYSTAL S. BROWN

PUBLIC UTILITIES ANALYST V

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

JANUARY 26, 2009

TABLE OF CONTENTS

SCHEDULES

EXECUTIVE SUMMARY
SULPHUR SPRINGS VALLEY ELECTRIC, INC.
DOCKET NO. E-01575A-08-0328

Sulphur Springs Valley Electric Cooperative, Inc. ("Sulphur Springs" or "Cooperative") is a certificated Arizona-based non-profit rural electric distribution cooperative. Sulphur Springs provides power and energy to approximately 50,000 customers in most of Cochise County and portions of Santa Cruz, Pima, and Graham counties, Arizona.

Sulphur Springs proposed a $10,881,590, or 11.75 percent, revenue increase from $92,613,559 to $103,495,149. The proposed revenue requirement would produce an operating margin of $17,132,688 for a 12.51 percent rate of return on an original cost rate base of $136,903,293. Sulphur Springs requests a 2.86 times interest earned ratio ("TIER").

Staff recommends a $6,353,795, or 6.78 percent, revenue increase from a Staff adjusted $93,744,087 to $100,097,882. This recommended revenue requirement would produce an operating margin of $15,042,800 for an 11.32 percent rate of return on a Staff adjusted original cost rate base of $132,886,202 and produces a 2.29 TIER.

STAFF RECOMMENDATIONS

1. Staff recommends revenue requirement of $100,097,882.

2. Staff further recommends denial of the Cooperative's request for a Debt Cost Adjustment Mechanism.

INTRODUCTION

Q. Please state your name, occupation, and business address.

A. My name is Crystal S. Brown. I am a Public Utilities Analyst V employed by the Arizona Corporation Commission ("ACC" or "Commission") in the Utilities Division ("Staff"). My business address is 1200 West Washington Street, Phoenix, Arizona 85007.

Q. Briefly describe your responsibilities as a Public Utilities Analyst V.

A. I am responsible for the examination and verification of financial and statistical information included in utility rate applications. In addition, I develop revenue requirements, prepare written reports, testimonies, and schedules that include Staff recommendations to the Commission. I am also responsible for testifying at formal hearings on these matters.

Q. Please describe your educational background and professional experience.

A. I received a Bachelor of Science Degree in Business Administration from the University of Arizona and a Bachelor of Science Degree in Accounting from Arizona State University.

Since joining the Commission in August 1996, I have participated in numerous rate cases and other regulatory proceedings involving electric, gas, water, and wastewater utilities. I have testified on matters involving regulatory accounting and auditing. Additionally, I have attended utility-related seminars sponsored by the National Association of Regulatory Utility Commissioners ("NARUC") on ratemaking and accounting designed to provide continuing and updated education in these areas.

Q. What is the scope of your testimony in this case?

A. I am presenting Staff's analysis and recommendations in the areas of rate base, operating revenues and expenses and revenue requirement regarding Sulphur Springs Valley Electric Cooperative, Inc.'s ("Sulphur Springs" or "Cooperative") application for a permanent rate increase. I am also presenting Staff's recommendation concerning the Cooperative's request for a new Debt Cost Adjustment Mechanism.

Q. Who else is providing Staff testimony and what issues will they address?

A. Staff witness Julie McNeely-Kirwan is presenting Staff's base cost of power recommendation. Ms. McNeely-Kirwan is also presenting Staff's recommendation concerning the Cooperative's requested tariff revisions and its request to include the pass-through of future generation and transmission costs associated with the Cooperative-owned generation and transmission facilities in its Wholesale Power Cost Adjustor. Staff witness Steve Irvine is presenting Staff's recommendations concerning the Cooperative's DSM program and its requested new DSM Adjustment Mechanism. Staff witness William Musgrove is presenting Staff's rate design recommendations. Staff witness Prem Bahl is presenting Staff's cost of service and engineering analysis and recommendations.

BACKGROUND

Q. Please review the background of this application.

A. Sulphur Springs is a certificated Arizona-based non-profit rural electric distribution cooperative. Sulphur Springs provides power and energy to approximately 50,000 customers in most of Cochise County and portions of Santa Cruz, Pima, and Graham counties, Arizona.

Sulphur Springs filed an application for a permanent rate increase on June 30, 2008. On July 30, 2008, Staff filed a letter declaring the application sufficient. Sulphur Springs' current rates were authorized in Decision No. 58358, dated July 23, 1993.

Q. What are the primary reasons for the Cooperative's requested permanent rate increase?

A. The Cooperative states that its adjusted test year operating income was $6,251,098 resulting in a 4.48 percent rate of return and a 0.82 operating times interest earned ratio ("TIER"). According to the Cooperative, the primary reasons it filed the application are to increase equity, increase annual cash flows, and to meet its financial objectives regarding the addition of new generation sources resulting from continuing growth within its service territory.

Q. Is Sulphur Springs requesting any other approvals?

A. Yes, Sulphur Springs is requesting:

1. A revision to its Wholesale Power Cost Adjustment to include the pass-through of future generation and transmission costs associated with the Cooperative-owned generation and transmission facilities;
2. A new Debt Cost Adjustment Mechanism that will permit the Cooperative to recover increases in interest costs associated with Commission-approved financing of plant additions;
3. Approval of its DSM Program (to the extent not already approved);
4. The inclusion of a portion of approved DSM program expenses in base rates with additional expenses and new DSM programs to be recovered through a new DSM Adjustment Mechanism and approval process; and
5. Approval of the revisions to its Tariffs and Service Conditions

CONSUMER SERVICES

Q. Please provide a brief history of customer complaints received by the Commission regarding Sulphur Springs.

A. Staff reviewed the Commission's records for the period of January 3, 2005 through November 25, 2008, and found 84 complaints and 73 inquiries. One complaint and two inquiries remain open pending final investigative results. All others have been resolved and closed. There were 13 opinions docketed opposing, and none favoring, the rate increase for the period of May 13, 2008 through November 25, 2008.

SUMMARY OF PROPOSED REVENUES

Q. Please summarize the Cooperative's filing.

A. The Cooperative proposes total annual revenue of $103,495,149 as shown on Schedule CSB-1. This proposed revenue provides a $10,881,590, or 11.75 percent, revenue increase over adjusted Test Year revenues of $92,613,559. Operating revenue of $103,495,149 would produce an operating margin of $17,132,688 for a 12.51 percent rate of return on an original cost rate base of $136,903,293 and produces a 2.86 net TIER.

Q. Please summarize Staff's recommended revenue.

A. Staff recommends total annual revenue of $100,097,882 as shown on Schedule CSB-1. This proposed revenue provides a $6,353,795 or 6.78 percent revenue increase over Staff adjusted Test Year revenues of $93,744,087. Operating revenue of $100,097,882 would produce an operating margin of $15,042,800 for an 11.32 percent rate of return on a Staff adjusted original cost rate base of $132,886,202 and produces a 2.29 operating TIER.

Q. Did Staff prepare a comparative analysis showing the details of the Cooperative proposed and the Staff recommended margin increase?

A. Yes. Staff's analysis is shown in the following table:

	Cooperative Proposed	Difference	Staff Recommended
Margin Revenue	$41,412,494	$(4,569,448)	$ 36,843,046
Other Revenue	$ 4,391,068	$ 253,375	$ 4,644,443
2008 Ft. Huachuca Rev	$ 0	$ 918,806	$ 918,806
Base Cost of Power Rev	$57,691,587	$ 0	$ 57,691,587
Total Annual Revenue	**$103,495,149**	**$(3,397,267)**	**$100,097,882**
Purchased Power Exp	$57,691,587	$ 0	$57,691,587
All Other Expenses	$28,670,874	$(1,307,380)	$27,363,494
Total Annual Expenses	**$86,362,461**	**$(1,307,380)**	**$85,055,081**
Oper Margin Before Int Exp	**$17,132,688**	**$(2,089,887)**	**$15,042,801**
Interest Exp on L.T. Debt	$ $7,532,556	$(426,301)	$ 7,106,255
Oper Margin After Int Exp	**$ 9,600,132**	**$(1,663,586)**	**$ 7,936,546**

Q. What test year did Sulphur Springs utilize in this filing?

A. Sulphur Springs' rate filing is based on the twelve months ended December 31, 2007 ("test year").

Q. Please summarize the rate base and operating margin recommendations and adjustments addressed in your testimony for Sulphur Springs.

A. My testimony addresses the following issues:

Rate Base Adjustments

Accumulated Depreciation, Automatic Meter Readers ("AMR's") – This adjustment increases rate base by $190,405 to remove accelerated depreciation not approved by the Commission.

Consumer Deposits and Advances – This adjustment decreases rate base by $459,598 to reflect test year-end consumer deposits and advances balances.

Deferred Credits – This adjustment decreases rate base by $917,955 to reflect non-Cooperative provided capital.

Materials and Prepayments – This adjustment decreases rate base by $2,829,944 to eliminate the Cooperative's recognition of working capital components that only increase rate base.

Operating Margin Adjustments

Revenue and Expense Annualizations – This adjustment increases revenues and expenses by $303,312 and 149,184, respectively, to reflect the revenues and expenses at the test year-end customer level.

Miscellaneous Service Charges – This adjustment decreases operating revenue by $91,590 to remove monies received for advances and/or contributions in aid of construction.

2008 Fort Huachuca Margin Increase – This adjustment increases operating revenue by $918,806 to reflect known and measurable Fort Huachuca contract changes.

Base Cost of Power and Wholesale Power Cost Adjustor ("WPCA") – This adjustment increases revenues as a result of matching the Base Cost of Power Revenue to the Staff proposed Base Cost of Power Expense and eliminating the WPCA revenues from operating revenues.

Demand Side Management Expenses – This adjustment decreases operating expenses by $484,996 to remove costs that Staff recommends to flow through an adjustor mechanism.

Employee Payroll, Benefits, and Payroll Taxes – This adjustment decreases operating expenses by $523,570 to remove payroll expenses for employees hired after the test year.

GDS Expenses – This adjustment decreases operating expenses by $51,427 to reflect consultant expenses incurred during the test year.

Normalized Legal Expenses – This adjustment decreases operating expenses by $52,892 to reflect legal expenses at a normalized level.

Charitable Contributions and Other Expenses – This adjustment decreases operating expenses by $298,622 to remove expenses that are voluntary and not needed for the provision of service.

Incentive Pay – This adjustment decreases operating expenses by $45,048 to remove optional expenses that are not needed for the provision of service.

Interest on Long-term Debt – This adjustment decreases net margins by $426,301 to reflect Staff's calculation of interest expense on long-term debt.

Capital Credits – This adjustment decreases net margins by $2,722,816 to reflect the portion of reported capital credits that are cash.

RATE BASE

Fair Value Rate Base

Q. Did the Cooperative prepare a schedule showing the elements of Reconstruction Cost New Rate Base?

A. No, the Cooperative did not. The Cooperative's filing treats the OCRB the same as the fair value rate base.

Rate Base Summary

Q. Please summarize Staff's adjustments to Sulphur Springs' rate base shown on Schedules CSB-2 and CSB-3.

A. Staff's adjustments to Sulphur Springs' rate base resulted in a net decrease of $4,017,091, from $136,903,293 to $132,886,202. This decrease was primarily due to Staff: (1) reflecting consumer deposits and advances at test year-end levels; (2) reflecting certain portions of the deferred credits recorded in the Cooperative's general ledger; and (3) removing the Cooperative's selective recognition of working capital components.

Rate Base Adjustment No. 1 – Accumulated Depreciation, Automated Meter Readers

Q. What is the Cooperative proposing for accumulated depreciation?

A. The Cooperative is proposing $72,528,240. As shown on Schedule CSB-4, the amount is composed of $72,337,835 of accumulated depreciation calculated using Commission approved depreciation rates and $190,405 of accumulated depreciation calculated using an accelerated depreciation rate not approved by the Commission.

Q. What is Staff's recommended treatment for the portion of the accumulated depreciation calculated with the accelerated depreciation rate?

A. The accelerated depreciation rate was not approved by the Commission, therefore, Staff recommends that the related depreciation expense be removed.

Q. What is Staff recommending?

A. Staff recommends that accumulated depreciation be decreased by $190,405 as shown on Schedule CSB-3 and CSB-4.

Rate Base Adjustment No. 2 – Consumer Deposits and Advances

Q. What are the Cooperative's actual test year-end consumer deposits and advances balances?

A. The Cooperative's actual test year-end consumer deposits and advances balances are $1,675,774 and $4,914,615, respectively.

Q. When is it appropriate to adjust actual test year-end balances?

A. It is appropriate to adjust actual test year-end balances when the adjustments provide a more realistic relationship between revenues, expenses, and rate base than the actual test year results.

Q. What adjustments to the consumer deposits and advances balances is the Cooperative proposing?

A. The Cooperative is proposing to decrease consumer deposits and advances by $169,231 and $290,367, respectively as a result of averaging the balances.

Q. What is the effect of averaging the balances?

A. The effect is that the capital provided by customers in the form of advances and deposits is understated which, in turn, results in an over-stated rate base.

Q. Does Sulphur Springs' adjustment to the consumer deposits and advances balances provide a more realistic relationship between revenues, expenses, and rate base?

A. No, it does not. The actual plant in service balance, which is the most significant component of rate base, was not averaged. Therefore, to be consistent with plant in service, the actual balances of consumer deposits and advances should also be used.

Q. What is Staff recommending?

A. Staff recommends decreasing rate base by $459,598 to reflect the actual test year end balances for consumer deposits and consumer advances as shown on Schedules CSB-3 and CSB-5.

Rate Base Adjustment 3 – Deferred Credit

Q. What was the Cooperative's deferred credit balance at the end of the test year?

A. The Cooperative's test year-end balance was $13,941,885. The individual amounts composing the total are shown on Schedule CSB-6.

Q. What deferred credits did the Cooperative include in rate base?

A. The Cooperative included $4,914,615 in deferred credits. The amount is reported as a separate item entitled "Consumer Advances" on Schedule CSB-2, line 5.

Q. Did Staff identify additional deferred credits that should be included in rate base?

A. Yes. Staff reviewed the Cooperative's response to data request CSB 2.3 and identified $917,955 in deferred credits. The amount consists of monies received for removing temporary power structures, pole attachments, joint use revenue, line extension payments, and uncashed patronage capital checks. This non-Cooperative provided capital decreases at the level of capital required to operate the utility and, therefore, should be recognized as a deduction from rate base.

Q. What is Staff recommending?

A. Staff recommends decreasing rate base by $917,955, which are deferred credits as shown on Schedules CSB-3 and CSB-6.

Rate Base Adjustment 4 – Materials and Prepayments

Q. What are the components of working capital?

A. The components of working capital as prescribed by the Arizona Administrative Code are cash working capital, materials and supplies, and prepaid expenses.

Q. Can total working capital be a negative amount that is deducted from rate base?

A. Yes, this can happen when cash working capital ("CWC") is negative and is larger than the sum of the materials, supplies, and prepayments.

Q. Does the Cooperative's proposal to include materials, supplies, and prepayments in working capital represent an inequitable adjustment to increase rate base?

A. Yes. The Cooperative chose not to conduct a lead-lag study, and accordingly, failed to reflect any customer provided capital in its working capital requirement.

It is inequitable for a company the size of Sulphur Springs to calculate working capital by using a method that ignores customer provided capital while guaranteeing a positive working capital result for Sulphur Springs. Had a lead-lag study been conducted, it might have shown that working capital is a negative component of rate base.

Q. What is Staff recommending?

A. Staff recommends removing $2,157,124 and $672,820 for materials and prepayments respectively as shown on Schedules CSB-3 and CSB-7.

Operating Margin

Operating Margin Summary

Q. What are the results of Staff's analysis of test year revenues, expenses and operating margin?

A. As shown on Schedules CSB-8 and CSB-9 Staff's analysis resulted in test year revenues of $93,744,087, expenses of $92,161,337 and operating margin after interest expense of $1,582,750.

Operating Margin Adjustment No. 1 – Revenue and Expense Annualizations

Q. What is the purpose of revenue and expense annualizations?

A. Revenue and expense annualizations are made to achieve matching with the year end rate base measurement date. The adjustments reflect the known and measurable changes to customer counts during the test year. Revenues are annualized to reflect sales that would have occurred if customers on the system at the end of the test year had taken service for the entire year. Likewise, variable expenses are annualized to reflect the increased costs to provide the level of sales related to year end customers.

Q. Has Staff analyzed growth in the number of customers served by Sulphur Springs?

A. Yes. Staff's analysis found that the number of customers grew at a rate of 1.99 percent from 2006 to 2007.

Q. How was the 1.99 growth rate used to annualize the revenues and expenses to end of year level?

A. Assuming the growth rate of 1.99 percent takes place evenly over the course of the year, then a 0.9935 percent adjustment is needed to annualize sales growth to the end of the test year.

To illustrate: At the beginning of the year, Sulphur Springs had a total of 48,769 customers as shown on Schedule CSB-10 line 20. At the end of the year, the actual number of customers was 49,738 as shown on Schedule CSB-10, line 19. To annualize the sales based on year-end customers, an adjustment of 0.9935 percent [((49,738-48,769)/ 48,769) / 2] is necessary.

Q. What is Staff recommending?

A. Staff recommends increasing revenues by $303,312 and expenses by $149,184 as shown on Schedules CSB-9 and CSB-10.

Operating Margin Adjustment No. 2 – Miscellaneous Service Charges

Q. What is the Cooperative proposing for Miscellaneous Service Charges?

A. The Cooperative is proposing $738,402 as shown on Schedule CSB-11, line 3.

Q. Did the Cooperative include advances and/or contributions in aid of construction in miscellaneous service charge revenue?

A. Yes. The Cooperative included $91,590.

Q. Is it appropriate to include advances and/or contributions in aid of construction in miscellaneous service charge revenue?

A. No, it is not. The RUS USOA indicates that monies received for advances or contributions should be treated as an offset to plant. Therefore, for ratemaking purposes, Staff is recommending that the advances and contributions be removed from operating revenue.

Q. What is Staff recommending?

A. Staff recommends decreasing revenues by $91,590 as shown on Schedules CSB-9 and CSB-11.

Operating Margin Adjustment No. 3 – 2008 Fort Huachuca Contract Margin Increase

Q. What is the Fort Huachuca Contract?

A. The Fort Huachuca contract is an operations, maintenance, and construction contract that the Cooperative has with the federal government.

Q. Were there known and measurable changes to the contract in 2008?

A. Yes. The Cooperative prepared a summary of the changes to revenues and expenses based upon known and measurable contract changes to prices and quantities as shown on Schedule CSB-12, column F.

Q. What is the increase in margin based upon these known and measurable changes?

A. The increase in margin (i.e., revenues less expenses) from 2007 is $918,806.

Q. What is Staff recommending?

A. Staff recommends increasing revenues by $918,806 as shown on Schedules CSB-9 and CSB-12.

Operating Margin Adjustment 4 – Base Cost of Power Revenue and Wholesale Power Cost Adjustor

Q. Explain the purpose of the break-out of the total revenue from sales of electricity into components as shown on Schedules CSB-9 and -13.

A. The purpose is to show the portion of revenue that is generated from base rates separately from revenue that is generated from margin revenue, and the wholesale power cost adjustor.

Q. What amount is Sulphur Springs proposing for Base Cost of Power Revenue and for its wholesale power cost adjustor ("WPCA")?

A. The Cooperative proposes $47,167,753 and $10,523,837 for its base cost of power revenue and WPCA respectively as shown on Schedules CSB-9 and CSB-13.

Q. Is it appropriate to include monies from the Cooperative's wholesale power cost adjustor in operating revenues?

A. No, it is not appropriate. The WPCA revenues are set using a mechanism that is different from that used to set base rates. Further, the WPCA can change outside of a rate case based on over or under collections in the Cooperative's fuel bank.

Q. Does Sulphur Springs' base cost of power revenue match its purchased power expense?

A. No. The Cooperative's filing reflects a $47,167,753 test year base cost of power revenue and a $57,691,587 test year purchased power expense.

Q. What is the cause of the mismatch?

A. The Cooperative made a pro forma adjustment to increase its purchased power expense by $10,523,837 but did not reflect this same increase in its base cost of power revenue.

Q. Should Sulphur Springs' test year base cost of power revenue equal purchased power expense?

A. Yes. The Cooperative has a purchased power adjustor mechanism that facilitates full recovery of all purchased power costs. The adjustor mechanism ensures that the Cooperative neither over nor under recovers purchased power cost. This means that changes in the cost of purchased power do not affect income. The difference between the amount collected from customers and the amount paid to power suppliers for purchased power in any year due to timing differences is reflected on the balance sheet as an asset or liability, not on the income statement.

Failure to recognize equal amounts for the revenue and expense associated with purchased power when an adjustor mechanism is in effect is inconsistent with the USOA. This mismatch results in a misstatement of income. Therefore, any pro forma adjustment to purchased power expense must be offset by an equal adjustment to base cost of power revenue.

Q. What is Staff recommending?

A. Staff recommends increasing base cost of power revenue by $10,523,837 to match the Cooperative's $57,691,587 purchased power expense and eliminating the $10,523,837 WPCA as shown on Schedules CSB-9 and CSB-13.

Operating Margin Adjustment 5 – Demand Side Management ("DSM") Expenses

Q. What are DSM expenses?

A. DSM expenses are incurred to reduce the amount of usage through customer education and other programs.

Q. What amount in DSM costs did the Cooperative report in the test year?

A. The Company reported $484,996 in DSM costs as shown on Schedule CSB-14.

Q. Is Staff recommending an adjustor mechanism for the Cooperative's DSM costs?

A. Yes. As discussed in the testimony of Steve Irvine, Staff is recommending an adjustor mechanism that will allow the Cooperative to recover or refund changes in its DSM costs without filing a permanent rate increase application. Therefore, these costs should be removed from the revenue requirement.

Q. What is Staff recommending?

A. Staff recommends decreasing operating expense by $484,996 as shown on Schedule CSB-9 and CSB-14.

Operating Margin Adjustment No. 6 – Employee Payroll, Benefits, and Payroll Taxes

Q. What adjustment did the Cooperative propose for employee payroll, benefits, and payroll taxes?

A. The Cooperative proposed to increase operating expenses by $1,021,207 to reflect the employee payroll, benefits, and payroll taxes of 189 full-time employees and 16 part-time employees using 2008 wage levels. The full-time employee count of 189 included 10 employees that were employed by April 2008.

Q. Is recognition of the increased payroll costs of employees that were employed during the test year appropriate?

A. Yes, recognition is appropriate because the increased payroll cost of its test year employees is known and measurable and not based upon customer growth.

Q. Is recognition of the ten employees hired after the test year appropriate?

A. No, it is not. Staff determined through the Cooperative's response to data request CSB 2.21 that the additional cost of the ten new employees hired in 2008 would be offset by ten employees who would be leaving the Cooperative in 2008.

Q. What is Staff recommending?

A. Staff recommends decreasing operating expense by $523,570 as shown on Schedules CSB-9 and CSB-15.

Operating Margin Adjustment No. 7 – GDS Expenses

Q. What services does GDS provide to Sulphur Springs?

A. Sulphur Springs has been working toward becoming a partial requirements member of Arizona Electric Power Cooperative ("AEPCO"). Sulphur Springs employs GDS to provide assistance with evaluating and negotiating power contracts and dealing with related power procurements issues.

Q. What amount was included in test year expenses for GDS?

A. The Cooperative included $212,217 in test year expenses as shown on Schedule CSB-16.

Q. What adjustment did Staff make?

A. Staff removed $71,305 to remove costs that did not occur during the test year and added $19,879 to reflect two invoices that were incurred during the test year but were not included in the $212,217 total.

Q. What is Staff recommending?

A. Staff recommends decreasing administrative and general expense by $51,427 as shown on Schedules CSB-9 and CSB-16.

Operating Margin Adjustment No. 8 – Normalized Legal Expenses

Q. What did the Cooperative propose for legal expenses?

A. The Cooperative proposed $95,837 as shown on Schedule CSB-17.

Q. What adjustment did Staff make?

A. Staff identified legal expenses incurred for financings, tariffs, and litigation over easements that are not expected to be ongoing in future years at the same level. Therefore, Staff normalized the amounts over three years.

Q. What is Staff recommending?

A. Staff recommends decreasing administrative and general expense by $52,892 as shown on Schedules CSB-9 and CSB-17.

Operating Margin Adjustment No. 9 – Charitable Contributions and Other Expenses

Q. What is Sulphur Springs proposing for charitable contributions and other expenses?

A. Sulphur Springs is proposing $343,752 for charitable contributions and other expenses as shown on Schedule CSB-18. The amount is composed of $298,622 for charitable contributions, sponsorships, food, entertainment, and similar expenses; $137,970 for dues and memberships to industry organizations; $21,616 for employee meals during work-related travel; and $100,138 for advertising that educates the public on safety and other issues.

Q. What ratemaking treatment does Staff recommend for the expenses?

A. Since charitable contributions, sponsorships, food, entertainment, and similar expenses are voluntary costs, the $298,622 expense is not necessary to provide service. Consequently, Staff recommends that it be recognized as non-operating expenses and excluded from the revenue requirement. The remaining $45,130 in expenses are needed in the provision.

Q. What is Staff recommending?

A. Staff recommends decreasing operating expense by $298,622 as shown on Schedules CSB-9 and CSB-18.

Operating Margin Adjustment No. 10 – Incentive Pay

Q. What is Sulphur Springs proposing for incentive pay?

A. Sulphur Springs is proposing $46,241 for incentive pay as shown on Schedule CSB-19.

Q. Are incentive pay costs necessary to provide safe and reliable service?

A. No, incentive pay costs are not necessary to provide safe and reliable service. Sulphur Springs pays its employees competitive salary, wage and benefits packages with regular annual wage increases. These costs are designed to compensate the employees to perform work that will enable the Cooperative to provide safe and reliable service. Therefore, the cost of the employees' base salaries and wages is a required cost. The incentive pay is an optional cost and, therefore, should be recognized below-the-line (i.e., removed from rates).

Q. What is Staff recommending?

A. Staff recommends decreasing operating expense by $45,057 as shown on Schedules CSB-9 and CSB-19.

Operating Margin No. 11 – Interest Expense on Long-term Debt

Q. What is the Cooperative proposing for Interest Expense on Long-term Debt?

A. Sulphur Springs is proposing $6,994,249 for Interest Expense on Long-term Debt. The debt is financed through the National Rural Utilities Cooperative Finance Cooperation ("CFC"). The interest expense amount was calculated by applying the applicable interest rate to (1) the outstanding principal at the end of the test year, plus (2) an additional CFC draw of $10,067,666 subsequent to the end of the test year, plus (3) an anticipated CFC draw of $18 million at 4.9 percent.

Q. What adjustment did Staff make to Interest Expense on Long-term Debt?

A. Staff adjusted the interest expense on the "anticipated CFC draw of $18 million" to reflect the interest expense on the actual CFC draw of $9.3 million as of November 7, 2008[1].

[1] The most recent date available that would allow Staff sufficient time to prepare its direct case.

Q. What is Staff recommending?

A. Staff recommends decreasing Interest Expense on Long-term Debt by $426,301 as shown on Schedules CSB-9 and CSB-20.

Operating Margin Adjustment No. 12 – Capital Credits

Q. What are capital credits?

A. Capital credits are ownership interests cooperatives receive as a result of doing business with another cooperative. For example, the net margins (or profit) of generation and transmission cooperatives are distributed through capital credits to the distribution cooperatives that buy power from them. Capital credits are required to be reported in the income statement as non-operating revenue.

Q. What amount is Sulphur Springs proposing for Capital Credits?

A. The Cooperative proposes $3,110,503 for Capital Credits as shown on Schedule CSB-21.

Q. Do Capital Credits necessarily represent cash receipts?

A. No. Capital credits are earnings from another cooperative, only some of which might be received in cash as a distribution. Capital credits are accounting income. The dollar amount cooperatives report as capital credits on the income statement will differ from the cash amount they actually receive because capital credits received in one year are generally paid in a subsequent year.

Q. What adjustment did Staff make?

A. Staff removed non-cash capital credits to only reflect actual cash received.

Q. What is Staff recommending?

A. Staff recommends decreasing capital credits account by $2,722,816 as shown on Schedules CSB-9 and CSB-21.

REVENUE REQUIREMENT – DEBT SERVICE COVERAGE

Q. What are the primary factors considered in determining the Cooperative's revenue requirement?

A. Staff's revenue requirement is primarily driven by the revenues needed to pay the principal and interest on long-term debt, and to meet the minimum 1.35 debt service coverage ("DSC") ratio required by the CFC. Additionally, Staff's revenue requirement provides sufficient cash flow to pay operating expenses and to build equity.

Q. What was the amount of the Cooperative's outstanding long-term debt at the end of the test year, and what was the test year interest expense incurred?

A. At the end of the test year, the Cooperative had $97,760,014 in long-term debt, and it incurred $5,800,108 in interest expense.

Q. Has the Commission recently approved a $70 million CFC loan?

A. Yes, in Decision No. 70027, dated December 4, 2007.

Q. Did Staff consider this loan in the determination of the Cooperative's revenue requirement?

A. Yes, Staff's revenue is sufficient to pay the principal and interest payments on the loan when fully drawn.

Q. Would you please briefly define the debt service coverage ratio ("DSC") and the times interest earned ratio ("TIER")?

A. DSC measures an entity's ability to generate cash flow to pay its debt service obligations (interest and principal) from operating activities. It is calculated by dividing (1) earnings before interest, taxes, and depreciation expense by (2) the principal and interest payments. When DSC is greater than 1.0, operating cash flow is sufficient to cover debt obligations.

TIER measures the number of times operating income will cover interest on long-term debt. It is calculated by dividing (1) operating margin after interest on long-term debt plus interest on long-term debt by (2) interest on long-term debt. When TIER is greater than 1.0, operating income is sufficient to cover interest expense.

Q. What are Sulphur Springs' DSC and TIER requirements?

A. For the loan agreements Sulphur Springs has with the CFC, the DSC ratio requirement is 1.35. This requirement is contained in the mortgage agreement between the CFC and the Cooperative. There is no stated TIER requirement.

Q. Did Staff calculate the DSC differently than the Cooperative?

A. Yes.

Q. How does Sulphur Springs calculate DSC?

A. Sulphur Springs uses the DSC calculation prescribed by the CFC. The CFC includes revenues derived from activities that are not a part of the Cooperative's core electric retail sales business (i.e. non-operating margin interest revenue and cash capital credit revenue). The CFC calculation is as follows:

For any calendar year add (1) Operating Margins, (2) Non-Operating Margins-Interest, (3) Interest Expense on long-term debt, (4) Depreciation and Amortization Expense, and (5) cash received from capital credits. Divide the sum so obtained by the sum of all payments of Principal and Interest on long-term debt.

Q. How does Staff's DSC calculation differ from the Cooperative's?

A. Staff's calculation is similar but excludes non-operating revenue from interest and capital credits.

Q. Why does Staff exclude non-operating revenue in its DSC calculation?

A. Non-operating revenue tends to be inconsistent from year to year. Staff's calculation measures the Cooperative's ability to make principal and interest payments based solely on the Cooperative's core operating results. Since operating results are generally more consistent than non-operating results, Staff's calculation provides a more reliable indication of ability to service debt.

Q. What revenue is Staff recommending to satisfy Sulphur Springs's DSC and TIER requirements?

A. Staff recommends revenue of $100,097,882 to provide a 2.09 DSC and a 2.29 TIER. Staff's proposed revenue would generate enough cash flow to service the Cooperative's debt and comply with CFC debt coverage requirements, allow for reasonable contingencies, and build equity.

Q. What is Staff's recommended increase over the Staff adjusted test year revenue?

A. Staff's recommended revenue of $100,097,882 is a $6,353,795 (or a 6.78 percent) increase over the Staff adjusted test year revenue of $93,744,087.

Q. Is 6.78 percent representative of the increase to customer bills on average with Staff's recommended revenue requirement?

A. Customer bills are comprised of margin costs and the cost of purchased power. The margin cost portion of customer bills would increase on average by 6.78 percent. The cost of power portion of customer bills reflects, on average, the Cooperative's actual cost of purchased power. The cost of purchased power fluctuates and might result in a different increase or decrease in customers' bills.

DEBT COST ADJUSTMENT MECHANISM

Q. Please describe the Cooperative's request for a Debt Cost Adjustment Mechanism.

A. The Cooperative proposes to recover increases in interest costs associated with Commission-approved financing of plant through a Debt Cost Adjustment Mechanism.

Q. When is an adjustor mechanism appropriate?

A. An adjustor mechanism is appropriate when the cost to the utility is significantly large compared to the other expenses; when there are large changes to the expense from month to month that could seriously impact the Cooperative's financial health; and when the expense is not within the Cooperative's control such as mandated state or federal programs.

Q. Does the Cooperative currently have a Commission approved adjustor mechanism?

A. Yes, the Cooperative currently has a wholesale power cost adjustor for its purchased power expense.

Q. Would you please discuss why the Cooperative's wholesale power cost adjustor is appropriate?

A. Yes. The Cooperative's purchased power expense compared to its total operating expense is significantly large. Staff's recommended $57,691,587 in purchased power expense represents approximately 68 percent of the Cooperative's $91,224,329 in test year operating expenses. Further, the Cooperative cannot control the short-term customer demands for purchased power from month to month. During the summer months the differences between revenues collected from customers and the purchased power costs paid to its suppliers may be so large that it could seriously impact the Cooperative's financial health. The purchased power adjustor mechanism helps to ensure that the Cooperative recovers all of its purchased power costs.

Q. Does Staff agree that an interest adjustor is appropriate?

A. No, Staff does not. Interest expense does not change from month to month like purchased power expense and the interest payments are usually fixed over a specified number of years. The timing of interest expense is within the control of the Cooperative such that a rate application could be filed simultaneously with additional draw downs on approved debt. Moreover, the additional revenue needed to cover interest expense on long-term debt should be determined in a rate proceeding in which all costs are evaluated by the Commission. This is because increases in costs in one area may be offset by decreases in costs in another.

Q. What is Staff recommending?

A. Staff recommends that the interest adjustor not be approved.

Q. Does this conclude Staff's direct testimony?

A. Yes, it does.

Sulphur Springs Valley Electric Cooperative
Docket No. E-01575A-08-0328
Test Year Ended December 31, 2007

Schedule CSB-1

REVENUE REQUIREMENT

LINE NO.	DESCRIPTION		[A] COMPANY ORIGINAL COST		[B] STAFF ORIGINAL COST
1	Adjusted Operating Margin (Loss)	$	6,251,098	$	8,689,005
2	Depreciation and Amortization	$	7,574,650	$	7,574,650
3	Income Tax Expense		-		-
4	Long-term Interest Expense	$	6,994,249	$	6,567,948
5	Principal Repayment	$	4,269,396	$	4,269,396
6a	**Recommended Increase in Operating Revenue**	$	10,881,590	$	**6,353,795**
6b	**Percent Increase (Line 6a / Line 7) - Per Staff**		N/A		**6.78%**
6c	Percent Increase (Line 6a / $92,613,559) - Per Cooperative		11.75%		N/A
7	Adjusted Test Year Operating Revenue	$	92,613,559	$	93,744,087
8	**Recommended Annual Operating Revenue**	$	103,495,149	$	**100,097,882**
9a	**Recommended Operating Margin**	$	17,132,688	$	**15,042,800**
9b	Recommended Net Margin	$	12,990,628	$	7,936,545
10a	**Recommended Operating TIER (L3+L9)/L4 - Per Staff**		N/A		**2.29**
10b	Recommended Net TIER - Per Cooperative		2.86		N/A
11a	**Recommended DSC (L2+L3+L9)/(L4+L5) - Per Staff**		N/A		**2.09**
11b	Recommended DSC (L2+L4+L9b)/(L4+L5) - Per Cooperative		2.45		N/A
12	**Adjusted Rate Base**	$	136,903,293	$	**132,886,202**
13	Rate of Return (L9a / L12)		12.51%		11.32%

References:
Column [A]: Company Schedules A-1, C-1, C-3
Column [B]: Staff Schedules CSB-2, CSB-11, Testimony

Sulphur Springs Valley Electric Cooperative
Docket No. E-01575A-08-0328
Test Year Ended December 31, 2007

Schedule CSB-2

RATE BASE - ORIGINAL COST

LINE NO.		[A] COMPANY AS FILED	[B] STAFF ADJUSTMENTS	[C] STAFF AS ADJUSTED
1	Plant in Service	$ 212,732,380	$ -	$ 212,732,380
2	Less: Acc Depreciation & Amortization	(72,528,240)	190,405	(72,337,835)
3	Net Plant in Service	$ 140,204,140	$ 190,405	$ 140,394,545
	LESS:			
4	Consumer Deposits	$ (1,506,543)	$ (169,231)	$ (1,675,774)
5	Consumer Advances	$ (4,624,248)	$ (290,367)	$ (4,914,615)
6	Deferred Credits	$ -	$ (917,955)	$ (917,955)
7	Total	(6,130,791)	(1,377,552)	(7,508,343)
	ADD:			
8	Cash Working Capital	$ -	$ -	$ -
9	Materials and Supplies	$ 2,157,124	$ (2,157,124)	$ -
10	Prepayments	$ 672,820	$ (672,820)	$ -
11	Total	$ 2,829,944	$ (2,829,944)	$ -
12	**Total Rate Base**	$ 136,903,293	$ (4,017,091)	$ 132,886,202

References:
Column [A], Cooperative Schedule B-1
Column [B]: Schedules CSB-2 through CSB-7
Column [C]: Column [A] + Column [B]

Sulphur Springs Valley Electric Cooperative
Docket No. E-01575A-08-0328
Test Year Ended December 31, 2007

SUMMARY OF RATE BASE ADJUSTMENTS

LINE NO.	Acct. No.	DESCRIPTION	[A] COOPERATIVE AS FILED	[B] Accumulated Depreciation AMR's ADJ No.1 Ref: Sch CSB-4	[C] Consumer Deposits and Advances ADJ No. 2 Ref: Sch CSB-5	[D] Deferred Credits ADJ No. 3 Ref: Sch CSB-6	[E] Materials and Prepayments ADJ No. 4 Ref: Sch CSB-7	[F] STAFF ADJUSTED
		PLANT IN SERVICE:						
1	303	Intangible Plant	$ 46,500	$ -	$ -	$ -	$ -	$ 46,500
2	350	Transmission Plant - Land and Land Rights	$ 633,768	$ -	$ -	$ -	$ -	$ 633,768
3	353	Transmission Plant - Station Equipment	$ 933,201	$ -	$ -	$ -	$ -	$ 933,201
4	355	Transmission Plant - Poles and Fixtures	$ 2,774,629	$ -	$ -	$ -	$ -	$ 2,774,629
5	356	Transmission Plant - OH Conductors	$ 5,630,063	$ -	$ -	$ -	$ -	$ 5,630,063
6	360	Distribution Plant - Land and Land Rights	$ 124,706	$ -	$ -	$ -	$ -	$ 124,706
7	361	Distribution Plant - Structures and Improvements	$ 5,191	$ -	$ -	$ -	$ -	$ 5,191
8	362	Distribution Plant - Substation Equipment	$ 18,024,631	$ -	$ -	$ -	$ -	$ 18,024,631
9	364	Distribution Plant - Poles, Towers, and Fixtures	$ 34,444,295	$ -	$ -	$ -	$ -	$ 34,444,295
10	365	Distribution Plant - Conductors and Devices	$ 22,877,936	$ -	$ -	$ -	$ -	$ 22,877,936
11	366	Distribution Plant - Underground Conduit	$ 16,753,223	$ -	$ -	$ -	$ -	$ 16,753,223
12	367	Distribution Plant - Underground Conductors	$ 26,203,285	$ -	$ -	$ -	$ -	$ 26,203,285
13	368	Distribution Plant - Transformers	$ 40,732,770	$ -	$ -	$ -	$ -	$ 40,732,770
14	369	Distribution Plant - Services	$ 8,532,859	$ -	$ -	$ -	$ -	$ 8,532,859
15	370	Distribution Plant - Meters	$ 9,336,411	$ -	$ -	$ -	$ -	$ 9,336,411
16	371	Distribution Plant - Install. On Customers Premises	$ 1,316,138	$ -	$ -	$ -	$ -	$ 1,316,138
17	373	Distribution Plant - Street Lighting and Signal Syst	$ 2,135,425	$ -	$ -	$ -	$ -	$ 2,135,425
18	389	General Plant - Land and Land Rights	$ 807,670	$ -	$ -	$ -	$ -	$ 807,670
19	390	General Plant - Structures and Improvements	$ 7,019,401	$ -	$ -	$ -	$ -	$ 7,019,401
20	391	General Plant - Office Furniture and Equipment	$ 3,231,257	$ -	$ -	$ -	$ -	$ 3,231,257
21	392	General Plant - Transportation Equipment	$ 4,353,642	$ -	$ -	$ -	$ -	$ 4,353,642
22	393	General Plant - Stores Equipment	$ 293,929	$ -	$ -	$ -	$ -	$ 293,929
23	394	General Plant - Tools, Shop, & Garage Equipment	$ 1,368,880	$ -	$ -	$ -	$ -	$ 1,368,880
24	395	General Plant - Laboratory Equipment	$ 774,153	$ -	$ -	$ -	$ -	$ 774,153
25	396	General Plant - Power Operated Equipment	$ 7,085,730	$ -	$ -	$ -	$ -	$ 7,085,730
26	397	General Plant - Communications Equipment	$ 903,184	$ -	$ -	$ -	$ -	$ 903,184
27	398	General Plant - Miscellaneous	$ (3,682,314)	$ -	$ -	$ -	$ -	$ (3,682,314)
28	399	General Plant - Contributed dollars	$ 71,817	$ -	$ -	$ -	$ -	$ 71,817
29		Total Plant in Service	$ 212,732,380	$ -	$ -	$ -	$ -	$ 212,732,380
30		Less: Accumulated Depreciation	$ (72,528,240)	$ 190,405	$ -	$ -	$ -	$ (72,337,835)
31		Less: Accumulated Amortization	-	-	-	-	-	-
32		Total Accumulated Depreciation & Amortization	$ (72,528,240)	$ 190,405	$ -	$ -	$ -	$ (72,337,835)
33		Net Plant in Service	$ 140,204,140	$ 190,405	$ -	$ -	$ -	$ 140,394,545
		LESS:						
34		Consumer Deposits	$ (1,506,543)	$ -	$ (169,231)	$ -	$ -	$ (1,675,774)
35		Consumer Advances	$ (4,624,248)	$ -	$ (290,367)	$ -	$ -	$ (4,914,615)
36		Deferred Credits	$ -	$ -	$ -	$ (917,955)	$ -	$ (917,955)
37		Total	$ (6,130,791)	$ -	$ (459,598)	$ (917,955)	$ -	$ (7,508,343)
		ADD:						
38		Cash Working Capital	$ -	$ -	$ -	$ -	$ -	$ -
39		Materials and Supplies	$ 2,157,124	$ -	$ -	$ -	$ (2,157,124)	$ -
40		Prepayments	$ 672,820	$ -	$ -	$ -	$ (672,820)	$ -
41		Total	$ 2,829,944	$ -	$ -	$ -	$ (2,829,944)	$ -
42		**Total Rate Base**	$ 136,903,293	$ 190,405	$ (459,598)	$ (917,955)	$ (2,829,944)	$ 132,886,202

Sulphur Springs Valley Electric Cooperative
Docket No. E-01575A-08-0328
Test Year Ended December 31, 2007

Schedule CSB-4

RATE BASE ADJUSTMENT NO. 1 - ACCUMULATED DEPRECIATION, AMR

		[A]	[B]	[C]
LINE NO.	DESCRIPTION	COMPANY AS FILED	STAFF ADJUSTMENTS	STAFF AS ADJUSTED
1	Accumulated Depreciation before Accelerated Depr	$ 72,337,835	$ (0)	$ 72,337,835
2	Accelerated Depreciation on AMR	190,405	(190,405)	-
3	Total	$ 72,528,240	$ (190,405)	$ 72,337,835

References:
Column [A]: Cooperative Schedules B-1.0
Column [B]: Testimony, CSB; Data Request Response CSB 3.11
Column [C]: Column [A] + Column [B]

Sulphur Springs Valley Electric Cooperative
Docket No. E-01575A-08-0328
Test Year Ended December 31, 2007

Schedule CSB-5

RATE BASE ADJUSTMENT NO. 2 - CONSUMER DEPOSITS AND ADVANCES

		[A]	[B]	[C]
LINE NO.	DESCRIPTION	COMPANY AS FILED	STAFF ADJUSTMENTS	STAFF AS ADJUSTED
1	Consumer Deposits	$ 1,506,543	$ 169,231	$ 1,675,774
2	Consumer Advances	4,624,248	290,367	4,914,615
3	Total	$ 6,130,791	$ 459,598	$ 6,590,389

References:
Column [A]: Cooperative Schedules B-1.0
Column [B]: Column [C] + Column [A]
Column [C]: Testimony, CSB; Cooperative Schedule B-3.0

Sulphur Springs Valley Electric Cooperative **Schedule CSB-6**
Docket No. E-01575A-08-0328
Test Year Ended December 31, 2007

RATE BASE ADJUSTMENT NO. 3 - DEFERRED CREDITS

			[A]		[B]		[C]
LINE NO.	**DESCRIF**	**DESCRIPTION**	**COMPANY AS FILED (Sch E-5)**		**STAFF ADJUSTMENTS**		**STAFF AS ADJUSTED**
1	Deferred Credits		$	-	$ 917,955	$	917,955

Account Number				
252.10	Cost to remove temporary power structures	$	32,464	
253.00	Poles attachments/joint use revenue	$	251,979	
253.10	Line extension payments	$	243,541	
253.26	Uncashed checks	$	389,971	
		$	**917,955**	**Total Deferred Credits Per Staff**
252.00	Consumer Advances for Construction	$	4,914,615	Separate rate base deduction
253.25	Alternative engergy collections	$	1,209,296	DSM costs
253.50	Over-collections of fuel adjustor	$	1,585,042	Fuel adjustor collections
253.97	Fort Huachuca - Deferred Revenue	$	5,314,977	Revenue billed but not received
	Total Staff Adjusted Deferred Credits	$	13,941,885	Total Deferred Credits Per G/L

References:
Column [A]: Cooperative Schedule B-1.0
Column [B]: Testimony, CSB; Cooperative Schedule C-1.0, Data Request 2.3
Column [C]: Column [A] + Column [B]

Sulphur Springs Valley Electric Cooperative
Docket No. E-01575A-08-0328
Test Year Ended December 31, 2007

Schedule CSB-7

RATE BASE ADJUSTMENT NO. 4 - WORKING CAPITAL

		[A]	[B]	[C]
LINE NO.	DESCRIPTION	COMPANY AS FILED	STAFF ADJUSTMENTS	STAFF AS ADJUSTED
1	Cash Working Capital	$ -	$ -	$ -
2	Materials and Supplies	$ 2,157,124	$ (2,157,124)	$ -
3	Prepayments	$ 672,820	$ (672,820)	$ -
4	**Total Working Capital**	**$ 2,829,944**	**$ (2,829,944)**	**$ -**

References:
Column [A]: Cooperative Schedules B-1.0 and B-3.0
Column [B]: Column [C] + Column [A]
Column [C]: Testimony, CSB

Sulphur Springs Valley Electric Cooperative
Docket No. E-01575A-08-0328
Test Year Ended December 31, 2007

Schedule CSB-8

OPERATING MARGIN - TEST YEAR AND STAFF PROPOSED

Line No.	DESCRIPTION	[A] COMPANY TEST YEAR AS FILED	[B] STAFF TEST YEAR ADJUSTMENTS	[C] STAFF TEST YEAR AS ADJUSTED	[D] STAFF RECOMMENDED CHANGES	[E] STAFF RECOMMENDED
	REVENUES:					
1	Margin Revenue (Non-Base Cost of Power)	$ 30,530,901	$ 303,312	$ 30,834,213	$ 6,008,830	$ 36,843,043
2	Rounding	$ 3	$ -	$ 3		$ 3
3	Margin Revenue	$ 30,530,904	$ 303,312	$ 30,834,216	$ 6,008,830	$ 36,843,046
4						
5	Base Cost of Power Revenue	$ 47,167,753	$ 10,523,837	$ 57,691,590	$ -	$ 57,691,590
6	Wholesale Power Cost Adjustor (WPCA)	$ 10,523,837	$ (10,523,837)	$ -	$ -	$ -
7	Rounding	$ (3)	$ -	$ (3)	$ -	$ (3)
8	Base Cost of Power and Adjustor Revenue	$ 57,691,587	$ -	$ 57,691,587	$ -	$ 57,691,587
9						
10	**Total Revenue from Sales of Electricity**	**$ 88,222,491**	**$ 303,312**	**$ 88,525,803**	**$ 6,008,830**	**$ 94,534,633**
11	Other Revenues	$ 4,391,068	$ (91,590)	$ 4,299,478	$ 344,965	$ 4,644,443
12	2008 Ft Huachuca Margin	$ -	$ 918,806	$ 918,806	$ -	$ 918,806
13	**Total Revenues**	**$ 92,613,559**	**$ 1,130,528**	**$ 93,744,087**	**$ 6,353,795**	**$ 100,097,882**
14						
15	*EXPENSES:*					
16	Purchased Power	$ 57,691,587	$ 0	$ 57,691,587	$ -	$ 57,691,587
17	Transmission Operation and Maintenance	$ 253,985	$ (1,354)	$ 252,631	$ -	$ 252,631
18	Distribution - Operations	$ 8,524,851	$ (155,438)	$ 8,369,413	$ -	$ 8,369,413
19	Distribution - Maintenance	$ 2,532,504	$ (47,196)	$ 2,485,308	$ -	$ 2,485,308
20	Consumer Accounting	$ 3,024,637	$ (54,014)	$ 2,970,623	$ -	$ 2,970,623
21	Customer Service	$ 680,691	$ (13,743)	$ 666,948	$ -	$ 666,948
22	Sales	$ 562,326	$ (3,831)	$ 558,495	$ -	$ 558,495
23	Administrative and General	$ 4,226,472	$ (1,031,803)	$ 3,194,669	$ -	$ 3,194,669
24	Depreciation and Amortization	$ 7,574,650	$ -	$ 7,574,650	$ -	$ 7,574,650
25	Taxes	$ 1,290,758	$ -	$ 1,290,758	$ -	$ 1,290,758
26	**Total Operating Expenses**	$ 86,362,461	$ (1,307,380)	$ 85,055,081	$ -	$ 85,055,081
27						
28	**Operating Margin Before Interest on L.T.- Debt**	$ 6,251,098	$ 2,437,907	$ 8,689,005	$ -	$ 15,042,800
29						
30	***INTEREST ON LONG-TERM DEBT & OTHER DEDUCTIONS***					
31	Interest on Long-term Debt	$ 6,994,249	$ (426,301)	$ 6,567,948	$ -	$ 6,567,948
32	Interest - Other	$ 366,551	$ -	$ 366,551	$ -	$ 366,551
33	Other Dedcutions	$ 171,756	$ -	$ 171,756	$ -	$ 171,756
34	**Total Interest & Other Deductions**	$ 7,532,556	$ (426,301)	$ 7,106,255	$ -	$ 7,106,255
35						
36	***MARGINS (LOSS) AFTER INTEREST EXPENSE***	$ (1,281,458)	$ 2,864,208	$ 1,582,750	$ -	$ 7,936,545
37						
38	***NON-OPERATING MARGINS***					
39	Interest Income	$ 141,825	$ -	$ 141,825	$ -	$ 141,825
40	Other Margins	$ 138,168	$ -	$ 138,168	$ -	$ 138,168
41	G&T Capital Credits	$ 2,592,402	$ (2,592,402)	$ -	$ -	$ -
42	Other Capital Credits	$ 518,101	$ (130,414)	$ 387,687	$ -	$ 387,687
43	**Total Non-Operating Margins**	$ 3,390,496	$ (2,722,816)	$ 667,680	$ -	$ 667,680
44						
45	***EXTRAORDINARY ITEMS***	$ -	$ -	$ -	$ -	$ -
46						
47	***NET MARGINS (LOSS)***	$ 2,109,038	$ 141,392	$ 2,250,430	$ -	$ 8,604,225
48						
49						
50	References:					
51	Column (A): Cooperative Schedule A					
52	Column (B): Schedule CSB-9					
53	Column (C): Column (A) + Column (B)					
54	Column (D): Schedule CSB-1					
55	Column (E): Column (C) + Column (D)					

Sulphur Springs Valley Electric Cooperative
Docket No. E-01575A-08-0328
Test Year Ended December 31, 2007

SUMMARY OF OPERATING MARGIN ADJUSTMENTS - TEST YEAR

LINE NO.	DESCRIPTION	[A] COMPANY AS FILED	[B] ADJ #1 Revenue and Expense Annualizations Ref: Sch CSB-10	[C] ADJ #2 Miscellaneous Service Charge Revenue Ref: Sch CSB-11	[D] ADJ #3 2008 Fort Huachuca Margin Increase Ref: Sch CSB-12	[E] ADJ #4 Base Cost of Power and Wholesale Pwr Cost Adjustor Ref: Sch CSB-13	[F] ADJ #5 Demand Side Management Expenses Ref: Sch CSB-14	[G] ADJ #6 Employee Payroll, Benefits and Payroll Taxes Ref: Sch CSB-15	[H] ADJ #7 GDS Expenses Ref: Sch CSB-16
	REVENUES:								
1	Margin Revenue (Non-Base Cost of Power)	$ 30,530,901	$ 303,312	$ -	$ -	$ -	$ -	$ -	$ -
2	Rounding	3	-	-	-	-	-	-	-
3	Margin Revenue	$ 30,530,904	$ 303,312	$ -	$ -	$ -	$ -	$ -	$ -
4									
5	Base Cost of Power Revenue	$ 47,167,753	$ -	$ -	$ -	$ 10,523,837	$ -	$ -	$ -
6	Wholesale Power Cost Adjustor (WPCA)	10,523,837	-	-	-	(10,523,837)	-	-	-
7	Rounding	(3)	-	-	-	-	-	-	-
8	Base Cost of Power and Adjustor Revenue	$ 57,691,587	$ -	$ -	$ -	$ -	$ -	$ -	$ -
9									
10	Total Revenue from Sales of Electricity	$ 88,222,491	$ 303,312	$ -	$ -	$ -	$ -	$ -	$ -
11	Other Revenues	$ 4,391,068	$ -	$ (91,590)	$ -	$ -	$ -	$ -	$ -
12	2008 Ft Huachuca Margin	-	-	-	918,806	-	-	-	-
13	**Total Revenues**	**$ 92,613,559**	**$ 303,312**	**$ (91,590)**	**$ 918,806**	**$ -**	**$ -**	**$ -**	**$ -**
14									
15	**OPERATING EXPENSES:**								
16	Purchased Power	$ 57,691,587	$ -	$ -	$ -	$ 0	$ -	$ -	$ -
17	Transmission Operation and Maintenance	253,985	2,523	-	-	-	-	(3,570)	-
18	Distribution - Operations	8,524,851	84,691	-	-	-	-	(221,101)	-
19	Distribution - Maintenance	2,532,504	25,159	-	-	-	-	(66,622)	-
20	Consumer Accounting	3,024,637	30,049	-	-	-	-	(77,402)	-
21	Customer Service	680,691	6,762	-	-	-	-	(18,880)	-
22	Sales	562,326	-	-	-	-	-	(3,527)	-
23	Administrative and General	4,226,472	-	-	-	-	(484,996)	(132,467)	(51,427)
24	Depreciation and Amortization	7,574,650	-	-	-	-	-	-	-
25	Taxes	1,290,758	-	-	-	-	-	-	-
26	**Total Operating Expenses**	$ 86,362,461	$ 149,184	$ -	$ -	$ 0	$ (484,996)	$ (523,570)	$ (51,427)
27									
28	**Operating Margin Before Interest on L.T.- Debt**	**$ 6,251,098**	**$ 154,128**	**$ (91,590)**	**$ 918,806**	**$ (0)**	**$ 484,996**	**$ 523,570**	**$ 51,427**
29									
30	***INTEREST ON LONG-TERM DEBT & OTHER DEDUCTIONS***								
31	Interest on Long-term Debt	$ 6,994,249	$ -	$ -	$ -	$ -	$ -	$ -	$ -
32	Interest - Other	$ 366,551	-	-	-	-	-	-	-
33	Other Dedcutions	171,756	-	-	-	-	-	-	-
34	**Total Interest & Other Deductions**	$ 7,532,556	$ -	$ -	$ -	$ -	$ -	$ -	$ -
35									
36	***MARGINS (LOSS) AFTER INTEREST EXPENSE***	**$ (1,281,458)**	**$ 154,128**	**$ (91,590)**	**$ 918,806**	**$ (0)**	**$ 484,996**	**$ 523,570**	**$ 51,427**
37									
38	***NON-OPERATING MARGINS***								
39	Interest Income	$ 141,825	$ -	$ -	$ -	$ -	$ -	$ -	$ -
40	Other Margins	$ 138,168							
41	G&T Capital Credits	$ 2,592,402							
42	Other Capital Credits	518,101	-	-	-	-	-	-	-
43	**Total Non-Operating Margins**	$ 3,390,496	$ -	$ -	$ -	$ -	$ -	$ -	$ -
44									
45	***EXTRAORDINARY ITEMS***	$ -	-	-	-	-	-	-	-
46									
47	***NET MARGINS (LOSS)***	$ 2,109,038	$ 154,128	$ (91,590)	$ 918,806	$ (0)	$ 484,996	$ 523,570	$ 51,427

LINE NO.	DESCRIPTION	[I] ADJ #8 Normalized Legal Expenses Ref: Sch CSB-17	[J] ADJ #9 Charitable Contributions and Other Expenses Ref: Sch CSB-18	[K] ADJ #10 Incentive Pay Ref: Sch CSB-19	[L] ADJ #11 Interest Expense on L.T. Debt Ref: Sch CSB-20	[M] ADJ #12 Capital Credits Ref: Sch CSB-21	[N] STAFF ADJUSTED
	REVENUES:						
1	Margin Revenue (Non-Base Cost of Power)	$ -	$ -	$ -	$ -	$ -	$ 30,834,213
2	Rounding	-	$ -	$ -	$ -	$ -	3
3	Margin Revenue	$ -					$ 30,834,216
4							
5	Base Cost of Power Revenue	$ -	$ -	$ -	$ -	$ -	$ 57,691,590
6	Wholesale Power Cost Adjustor (WPCA)	-	-	-	-	-	-
7	Rounding	-	-	-	-	-	(3)
8	Base Cost of Power Revenue	$ -	$ -	$ -	$ -	$ -	$ 57,691,587
9							
10	Total Revenue from Sales of Electricity	$ -	$ -	$ -	$ -	$ -	$ 88,525,803
11	Other Revenues	$ -	$ -	$ -	$ -	$ -	$ 4,299,478
12	2008 Ft Huachuca Margin	-	-	-	-	-	918,806
13	**Total Revenues**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 93,744,087**
14							
15	***OPERATING EXPENSES:***						
16	Purchased Power	$ -	$ -	$ -	$ -	$ -	$ 57,691,587
17	Transmission Operation and Maintenance	-	-	(307)	-	-	252,631
18	Distribution - Operations	-	-	(19,028)	-	-	8,369,413
19	Distribution - Maintenance	-	-	(5,733)	-	-	2,485,308
20	Consumer Accounting	-	-	(6,661)	-	-	2,970,623
21	Customer Service	-	-	(1,625)	-	-	666,948
22	Sales	-	-	(304)	-	-	558,495
23	Administrative and General	(52,892)	(298,622)	(11,400)	-	-	3,194,669
24	Depreciation and Amortization	-	-	-	-	-	7,574,650
25	Taxes	-	-	-	-	-	1,290,758
26	**Total Operating Expenses**	$ (52,892)	$ (298,622)	$ (45,058)	$ -	$ -	$ 85,055,081
27							
28	**Operating Margin Before Interest on L.T.- Debt**	**$ 52,892**	**$ 298,622**	**$ 45,058**	**$ -**	**$ -**	**$ 8,689,005**
29							
30	***INTEREST ON LONG-TERM DEBT & OTHER DEDUCTIONS***						
31	Interest on Long-term Debt	$ -	$ -	$ -	$ (426,301)	$ -	$ 6,567,948
32	Interest - Other	-	-	-	-	-	366,551
33	Other Dedcutions	-	-	-	-	-	171,756
34	**Total Interest & Other Deductions**	$ -	$ -	$ -	$ (426,301)	$ -	$ 7,106,255
35							
36	***MARGINS (LOSS) AFTER INTERST EXPENSE***	**$ 52,892**	**$ 298,622**	**$ 45,058**	**$ 426,301**	**$ -**	**$ 1,582,750**
37							
38	***NON-OPERATING MARGINS***						
39	Interest Income	$ -	$ -	$ -	$ -	$ -	$ 141,825
40	Other Margins		-	-	-	-	138,168
41	G&T Capital Credits		-	-	-	(2,592,402)	-
42	Other Capital Credits	-	-	-	-	(130,414)	387,687
43	**Total Non-Operating Margins**	$ -	$ -	$ -	$ -	$ (2,722,816)	$ 667,680
44							
45	***EXTRAORDINARY ITEMS***	-	-	-		-	-
46							
47	***NET MARGINS (LOSS)***	$ 52,892	$ 298,622	$ 45,058	$ 426,301	$ (2,722,816)	$ 2,250,430

Sulphur Springs Valley Electric Cooperative
Docket No. E-01575A-08-0328
Test Year Ended December 31, 2007

Schedule CSB-10

OPERATING MARGIN ADJUSTMENT NO. 1 - REVENUE AND EXPENSE ANNUALIZATIONS

LINE NO.	DESCRIPTION	[A] COMPANY AS FILED	[B] STAFF ADJUSTMENTS	[C] STAFF AS ADJUSTED
1	Total Margin Revenues	$ 30,530,904	$ -	$ 30,530,904
2	Cooperative's Annualization for Large Pwr Cust	-	(368,953)	(368,953)
3	Total Margin Revenues to be annualized	$ 30,530,904	$ (368,953)	$ 30,161,951
4	Factor to Annualize Revenues to End of Test Year	0.00%		0.9935%
5	**Revenue Annualization Adjustment**	$ -	**$ 303,312**	$ 303,312
6				
7	**Variable Expenses Not Recovered Through Fuel Adjustor**			
8	Transmission - Operation and Maintenance	$ 253,985	$ 2,523	$ 256,508
9	Distribution - Operations	$ 8,524,851	$ 84,691	$ 8,609,542
10	Distribution - Maintenance	$ 2,532,504	$ 25,159	$ 2,557,663
11	Customer Accounting	$ 3,024,637	$ 30,049	$ 3,054,686
12	Customer Service	$ 680,691	$ 6,762	$ 687,453
13		$ 15,016,668	**$ 149,184**	$ 15,165,852
14				
15				

LINE NO.	Calculation of Annualization Factor	
19	49,738	2007 Year-end Customer Count per Form 7
20	48,769	2006 Year-end Customer Count per Form 7
21	969	
22	1.99%	Growth Rate (969 / 48,769)
23		
24	0.9935%	Annualization Factor - 2007 Growth Rate divided by 2
25		
26		
27		
28		

LINE NO.	Caculation of Variable Expenses Not Recovered Through Fuel Adjustor Description	Amount	2007 Growth Rate	Adjustment to Expenses
33	Transmission - Operation and Maintenance	$ 253,985	0.9935%	$ 2,523
34	Distribution - Operations	$ 8,524,851	0.9935%	$ 84,691
35	Distribution - Maintenance	$ 2,532,504	0.9935%	$ 25,159
36	Customer Accounting	$ 3,024,637	0.9935%	$ 30,049
37	Customer Service	$ 680,691	0.9935%	$ 6,762
38	Total Variable Expenses Not Recovered Through Fuel Adj	$ 15,016,668		$ 149,184

References:
Column A: Schedule CSB-9
Column B: Testimony, CSB
Column C: Column [A] + Column [B]

Sulphur Springs Valley Electric Cooperative **Schedule CSB-11**
Docket No. E-01575A-08-0328
Test Year Ended December 31, 2007

OPERATING MARGIN ADJUSTMENT NO. 2 - MISCELLANEOUS SERVICE CHARGE REVENUE

LINE NO.	DESCRIPTION	[A] COMPANY AS FILED	[B] STAFF ADJUSTMENTS	[C] STAFF AS ADJUSTED
1	Fort Huachuca	$ 2,822,220	$ -	$ 2,822,220
2	Electric Plant - Leased	$ 10,011	$ -	$ 10,011
3	Misc Service Charge Revenue	$ 738,402	$ (91,590)	$ 646,812
4	Rent from Electric Property	$ 819,651	$ -	$ 819,651
5	Other Electric Revenues	$ 783	$ -	$ 783
6	Total Other Revenues	$ 4,391,068	$ (91,590)	$ 4,299,478
7				
8				
9		Miscellaneous Service Charges		
10	Existing Member Connect Fee - Regular Hrs	$ 253,775	-	$ 253,775
11	Connect Fee - After Hours	$ 2,835	-	$ 2,835
12	Non-Pay Trip Fee - Regular Hours	$ 160,650	-	$ 160,650
13	Non-Pay Trip Fee - After Hours	$ 29,880	-	$ 29,880
14	Pump and Equipment Test	$ 480	-	$ 480
15	Radio Control Install Fee	$ 7,125	-	$ 7,125
16	Temporary Meter	$ 2,185	-	$ 2,185
17	Special After Hours Connect Fee	$ 620	-	$ 620
18	Aid to Construction - Line Extension	$ 91,590	(91,590)	$ -
19	Revenue from Lump Sum ISAC Payments	$ 34,117	-	$ 34,117
20	Late Charge	$ 124,033	-	$ 124,033
21	Penalty for Irrigation Override	$ 584	-	$ 584
22	Collection Service Charges Removed	$ (1,537)	-	$ (1,537)
23	Taxes Included in Service Charges in GL	$ 28,974	-	$ 28,974
24	Mileage Included in Service Charges in GL	$ 3,076	-	$ 3,076
25	NSF Check Reclassified	$ 15	-	$ 15
26	Total Misc Service Charge Revenue	$ 738,402	(91,590)	$ 646,812

References:

Column A: Cooperative provided workpaper
Column B: Testimony, CSB
Column C: Column [A] + Column [B]

Sulphur Springs Valley Electric Cooperative
Docket No. E-01575A-08-0328
Test Year Ended December 31, 2007

Schedule CSB-12

OPERATING MARGIN ADJUSTMENT NO. 3 - 2008 FORT HUACHUCA MARGIN INCREASE

LINE NO.	DESCRIPTION	[A] COMPANY AS FILED	[B] STAFF ADJUSTMENTS	[C] STAFF AS ADJUSTED
1	2008 Fort Huachuca Margin Increase	$ -	$ 918,806	$ 918,806
2				
3				
4				
5				
6				
7		[D]	[E]	[F]
8		$ 2,007	Increase in	$ 2,008
9		Fort Huachuca	Fort Huachuca	Fort Huachuca
10		**CSB 3.4**	Margins	**CSB 3.5**
11	Revenues	$ 2,824,391	$ 5,936,956	$ 8,761,346
12	Expenses	$ 1,447,039	$ 5,018,150	$ 6,465,189
13	Difference	$ 1,377,351	**$ 918,806**	$ 2,296,157

References:

Column A: Cooperative Schedule A-1
Column B: Testimony, CSB; Data Request Response CSB 3.4 and CSB 3.5
Column C: Column [A] + Column [B]

Sulphur Springs Valley Electric Cooperative
Docket No. E-01575A-08-0328
Test Year Ended December 31, 2007

Schedule CSB-13

OPERATING MARGIN ADJUSTMENT NO. 4 - BASE COST OF POWER AND WHOLESALE POWER COST ADJUSTOR

LINE NO.	DESCRIPTION	[A] COMPANY AS FILED	[B] STAFF ADJUSTMENTS	[C] STAFF AS ADJUSTED
1	***Revenues***			
2	Base Cost of Power Revenue ("BCOP")	$ 47,167,753	$ 10,523,834	$ 57,691,587
3	Rounding	(3)	3	-
4	Base Cost of Power Revenue Per Company	$ 47,167,750	$ 10,523,837	$ 57,691,587
5	Staff Recommended Increase To BCOP	-	-	-
6		$ 47,167,750	$ 10,523,837	$ 57,691,587
7	Wholesale Power Cost Adjustor ("WPCA")	10,523,837	(10,523,837)	-
8	Total Base Cost of Power and WPCA	57,691,587	-	57,691,587
9	***Expenses***			
10	Purchased Power	$ 57,691,587	$ 0	$ 57,691,587
11	**Operating Margin (Line 8 - Line 10)**	**$ -**	**$ (0)**	**$ (0)**
12				
13				
14				
15				
16				
17	Test Year Sales (In kWhs)	799,860,156	-	799,860,156
18	Multiplied by: Base Cost of Power per kWh	0.072127092	-	0.072127092
19	Total Base Cost of Power	$ 57,691,587	$ -	$ 57,691,587

References:

Column A: Cooperative Schedule A-1
Column B: Testimony, CSB
Column C: Column [A] + Column [B]

Sulphur Springs Valley Electric Cooperative
Docket No. E-01575A-08-0328
Test Year Ended December 31, 2007

Schedule CSB-14

OPERATING MARGIN ADJUSTMENT NO. 5 - DSM EXPENSES

LINE NO.	Acct. No.	DESCRIPTION	[A] COMPANY AS FILED CSB 5-2	[B] STAFF ADJUSTMENTS	[C] STAFF AS ADJUSTED
1	909.00	Production costs for Co-op Connection	$ 228	$ (228)	$ -
2	909.10	Printing costs for Co-op Connection	$ 8,634	$ (8,634)	$ -
3	909.10	Costs for Currents Magazine	$ 5,174	$ (5,174)	$ -
4	912.20	Rebates to existing homeowners	$ 94,800	$ (94,800)	$ -
5	912.40	Inspections on Touchstone Energy homes	$ 6,857	$ (6,857)	$ -
6	912.40	Manpower costs	$ 24,544	$ (24,544)	$ -
7	912.40	Newspaper costs to Tyau Advertising	$ 5,143	$ (5,143)	$ -
8	912.40	Radio advertising to Tyau Advertising	$ 4,582	$ (4,582)	$ -
9	912.40	TV advertising to Tyau Advertising	$ 6,290	$ (6,290)	$ -
10	912.55	Newspaper costs to Tyau Advertising	$ 6,523	$ (6,523)	$ -
11	912.55	Radio advertising to Tyau Advertising	$ 3,839	$ (3,839)	$ -
12	912.55	TV advertising to Tyau Advertising	$ 2,056	$ (2,056)	$ -
13	913.00	TV advertising to Tyau Advertising	$ 2,871	$ (2,871)	$ -
14	921.00	Newspaper costs to Tyau Advertising	$ 3,643	$ (3,643)	$ -
15	921.00	Radio advertising to Tyau Advertising	$ 4,575	$ (4,575)	$ -
16	921.00	TV advertising to Tyau Advertising	$ 21,814	$ (21,814)	$ -
17		Variance with amounts reported to ACC	$ 2,823	$ (2,823)	$ -
18		2007 DSM Costs reported to the ACC	$ 204,396	$ (204,396)	$ -
19	912.50	All Electric Rebates	$ 280,600	$ (280,600)	$ -
20		TOTAL	$ 484,996	$ (484,996)	$ -

References:
Column A: Cooperative Data Request Response CSB 5-2
Column B: Testimony, CSB
Column C: Column [A] + Column [B]

OPERATING MARGIN ADJUSTMENT NO. 6 - EMPLOYEE PAYROLL, BENEFITS, & PAYROLL TAXES

LINE NO.	DESCRIPTION	[A] COMPANY AS FILED	[B] STAFF ADJUSTMENTS	[C] STAFF AS ADJUSTED
1	Transmission Operation and Maintenance	$ 6,964	$ (3,570)	$ 3,394
2	Distribution - Operations	$ 431,251	$ (221,101)	$ 210,150
3	Distribution - Maintenance	$ 129,945	$ (66,622)	$ 63,322
4	Consumer Accounting	$ 150,970	$ (77,402)	$ 73,568
5	Customer Service	$ 36,825	$ (18,880)	$ 17,945
6	Sales	$ 6,880	$ (3,527)	$ 3,353
7	Administrative and General	$ 258,372	$ (132,467)	$ 125,906
8		**$ 1,021,207**	$ (523,570)	**$ 497,637**
9				

LINE NO.		Payroll	Employee Benefits	Payroll Tax	Total
10					
11					
12	Transmission Oper & Maint	$ 3,003	$ 138	$ 253	$ 3,394
13	Distribution - Operations	$ 185,955	$ 8,541	$ 15,654	$ 210,150
14	Distribution - Maintenance	$ 56,032	$ 2,574	$ 4,717	$ 63,322
15	Consumer Accounting	$ 65,098	$ 2,990	$ 5,480	$ 73,568
16	Customer Service	$ 15,879	$ 729	$ 1,337	$ 17,945
17	Sales	$ 2,967	$ 136	$ 250	$ 3,353
18	Administrative and General	$ 111,410	$ 5,117	$ 9,378	$ 125,906
19		$ 440,343	$ 20,226	$ 37,068	**$ 497,637**
20					
21					

LINE NO.		Payroll	Employee Benefits	Payroll Tax	Total	Percent to Total
22						
23						
24	Transmission Oper & Maint	$ 5,603	$ 882	$ 479	$ 6,964	0.68%
25	Distribution - Operations	$ 346,904	$ 54,856	$ 29,492	$ 431,251	42.23%
26	Distribution - Maintenance	$ 104,429	$ 16,369	$ 9,146	$ 129,945	12.72%
27	Consumer Accounting	$ 121,096	$ 19,395	$ 10,478	$ 150,970	14.78%
28	Customer Service	$ 29,528	$ 4,715	$ 2,583	$ 36,825	3.61%
29	Sales	$ 5,483	$ 910	$ 486	$ 6,880	0.67%
30	Administrative and General	$ 207,063	$ 33,442	$ 17,867	$ 258,372	25.30%
31		$ 820,106	$ 130,570	$ 70,531	**$ 1,021,207**	100.00%

References:

Column A: Cooperative Schedule A-3.0, Page 3 of 3;
Column B: Testimony, CSB; Data Request Response CSB 2.21
Column C: Column [A] + Column [B]

Sulphur Springs Valley Electric Cooperative
Docket No. E-01575A-08-0328
Test Year Ended December 31, 2007

Schedule CSB-15

Calculation of Staff Adjusted Payroll Expense

Line No.	Description	Company as Filed Sch A-7.0	Staff Adjustments	Staff as Adjusted
1	Actual test year payroll	$ 10,693,957	$ -	$ 10,693,957
2	Actual test year overtime	944,963	-	944,963
3		11,638,920	-	11,638,920
4				
5	Payroll for employees hired after test year	433,826	(433,826)	-
6	Adjustment to actual test year overtime	169,944	(169,944)	-
7	Reconciling item	18,134	(18,134)	-
8		621,904	(621,904)	-
9				
10	Adjusted total payroll	12,260,825	(621,904)	11,638,920
11	x Payroll expensed ratio	1	-	1
12	Adjusted Payroll Expenses	7,487,011	(379,763)	7,107,248
13	Less: Test year payroll expensed	6,666,905	-	6,666,905
14	**Test year adjusted payroll expense**	**820,106**	**(379,763)**	**440,343**

Calculation of Staff Adjusted Employee Benefits

Line No.	Description	Company as Filed Sch A-8.0	Staff Adjustments	Staff as Adjusted
1	Medical and Prescription	$ 1,030,671	$ (64,378)	$ 966,293
2	Vision	$ 20,457	$ (1,160)	$ 19,297
3	Dental	$ 64,986	$ (4,028)	$ 60,958
4	Life Insurance	$ 47,150	$ (1,805)	$ 45,345
5	Long-Term Disability	$ 93,347	$ -	$ 93,347
6	401K Plan	$ 328,225	$ -	$ 328,225
7	Defined Benefit Pension Plan	$ 1,987,943	$ -	$ 1,987,943
8	Retiree Benefits	$ 47,500	$ (91,537)	$ (44,037)
9	Postretirement Benefits	$ 526,067	$ -	$ 526,067
10	Workers Compensation	$ 176,234	$ -	$ 176,234
11	Total	$ 4,322,581	$ (162,908)	$ 4,159,673
12	x Expensed Ratio	67.734%		67.734%
13	Adjusted Benefits Expensed	$ 2,927,838	$ (110,344)	$ 2,817,495
14	Less: Test Year Expense	$ 2,797,269	$ -	$ 2,797,269
15	**Adjustment**	**$ 130,570**	**$ (110,344)**	**$ 20,226**

Calculation of Staff Adjusted Payroll Taxes

Line No.	Description	Company as Filed Sch A-13.0	Staff Adjustments	Staff as Adjusted
1	FICA	$ 907,617		$ 859,120
2	Federal Unemployment Taxes	$ 11,468		$ 10,908
3	State Unemployment Taxes	$ 7,454		$ 7,090
4	Total	$ 926,539		$ 877,118
5	x Payroll Expensed Ratio	$ 1		$ 1
6	Adjusted Payroll Taxes Expensed	$ 627,372		$ 593,909
7	Test Year Amount	$ 556,841		$ 556,841
8	Adjustment	$ 70,531		$ 37,068

Sulphur Springs Valley Electric Cooperative
Docket No. E-01575A-08-0328
Test Year Ended December 31, 2007

Schedule CSB-16

OPERATING MARGIN ADJUSTMENT NO. 7 - GDS EXPENSES

		[A]	[B]	[C]
LINE NO.	DESCRIPTION	COMPANY AS FILED CSB 3.13	STAFF ADJUSTMENTS	STAFF AS ADJUSTED
1	Administrative and General Expenses	$ 4,014,255	$ -	$ 4,014,255
2	Admin and General Exp, GDS Associates	$ 212,217	$ (51,427)	$ 160,790
3	Total Administrative and General Expenses	$ 4,226,472	$ (51,427)	$ 4,175,045
4			-	-
5				

LINE NO.				[D]	[E]	[F]
6						
7–9	Invoice No.	Invoice Date	DESCRIPTION	COMPANY AS FILED CSB 3.13	STAFF ADJUSTMENTS	STAFF AS ADJUSTED
10	52193	9/18/2006	GDS Associates, Inc.	$ 14,706	$ (14,706)	$ -
11	52759	10/18/2006	GDS Associates, Inc.	$ 20,767	$ (20,767)	$ -
12	53381	11/21/2006	GDS Associates, Inc.	$ 23,738	$ (23,738)	$ -
13	54020	12/18/2006	GDS Associates, Inc.	$ 12,094	$ (12,094)	$ -
14				$ 71,305	$ (71,305)	$ -
15						
16	54463	1/19/2007	GDS Associates, Inc.	$ 12,878	$ -	$ 12,878
17	55226	2/26/2007	GDS Associates, Inc.	$ 11,645	$ -	$ 11,645
18	55652	3/19/2007	GDS Associates, Inc.	$ 14,497	$ -	$ 14,497
19	56194	4/19/2007	GDS Associates, Inc.	$ 12,068	$ -	$ 12,068
20	56748	5/11/2007	GDS Associates, Inc.	$ 8,961	$ -	$ 8,961
21	57238	6/12/2007	GDS Associates, Inc.	$ 10,854	$ -	$ 10,854
22	57775	7/19/2007	GDS Associates, Inc.	$ 19,422	$ -	$ 19,422
23	58526	8/17/2007	GDS Associates, Inc.	$ 8,306	$ -	$ 8,306
24	59146	9/14/2007	GDS Associates, Inc.	$ 8,318	$ -	$ 8,318
25	59876	10/18/2007	GDS Associates, Inc.	$ 9,127	$ -	$ 9,127
26	60690	11/29/2007	GDS Associates, Inc.	$ 21,842	$ -	$ 21,842
27	61020	12/12/2007	GDS Associates, Inc.	$ 7,120	$ -	$ 7,120
28	81707	8/17/2007	GDS Associates, Inc.	$ (4,126)	$ -	$ (4,126)
29				$ 140,912	$ -	$ 140,912
30						
31				$ 212,217	$ (71,305)	$ 140,912
32						
33	61146	12/18/2007	GDS Associates, Inc.	$ -	$ 18,644	$ 18,644
34	61200	12/21/2007	GDS Associates, Inc.	$ -	$ 1,235	$ 1,235
35				$ -	$ 19,879	$ 19,879
36						
37			Total	$ 212,217	$ (51,427)	$ 160,790

References:
Column A: Cooperative Schedule A-1
Column B: Testimony, CSB; Data Request Response CSB 1.39, CSB 2.24, CSB 3.10, CSB 3.13
Column C: Column [A] + Column [B]

Sulphur Springs Valley Electric Cooperative
Docket No. E-01575A-08-0328
Test Year Ended December 31, 2007

Schedule CSB-17

OPERATING MARGIN ADJUSTMENT NO. 8 - NORMALIZED LEGAL EXPENSES

LINE NO.	DESCRIPTION	[A] COMPANY AS FILED CSB 5-2	[B] STAFF ADJUSTMENTS	[C] STAFF AS ADJUSTED
1	Administrative and General Expenses	$ 4,130,635	-	$ 4,130,635
2	Admin and General Exp, Legal Expenses	$ 95,837	(52,892)	$ 42,945
3	Total Administrative and General Expenses	$ 4,226,472	(52,892)	$ 4,173,580

LINE NO.	DESCRIPTION		[A] COMPANY AS FILED CSB 5-2	[B] STAFF ADJUSTMENTS	[C] STAFF AS ADJUSTED
1	Babacomari Ranch Company Litigation		$ 9,500	$ (6,333)	$ 3,167
2	2007 $70 Million Financing		$ 23,738	$ (15,826)	$ 7,913
3	CREBS ACC Financing Filing		$ 9,893	$ (6,595)	$ 3,298
4	2007-2008 Rest Plan & Tariff		$ 20,612	$ (13,741)	$ 6,871
5	Labor Matters		$ 32,094	$ (10,397)	$ 21,697
6			$ 95,837	$ (52,892)	$ 42,945
7					
8					
9	Babacomari Ranch Company Litigation	CSB 2.10	$ 9,500	normalized over 3 years	$ 3,167
10	2007 $70 Million Financing	CSB 2.14	$ 23,738	normalized over 3 years	$ 7,913
11	CREBS ACC Financing Filing	CSB 2.15	$ 9,893	normalized over 3 years	$ 3,298
12	2007-2008 Rest Plan & Tariff	CSB 2.16	$ 20,612	normalized over 3 years	$ 6,871
13			$ 63,743		$ 21,248
14					
15				2006 Labor Matters	$ 22,996
16				2007 Labor Matters	$ 32,094
17				2008 Labor Matters	$ 10,002
18					$ 65,092
19				normalized over 3 years	$ 3
20					$ 21,697

References:
Column A: Cooperative Schedule A-1
Column B: Testimony, CSB; Data Request Response CSB 1.37, CSB 2.10 to CSB 2.16
Column C: Column [A] + Column [B]

Sulphur Springs Valley Electric Cooperative
Docket No. E-01575A-08-0328
Test Year Ended December 31, 2007

Schedule CSB-18

OPERATING MARGIN ADJUSTMENT NO. 9 - CHARITABLE CONTRIBUTIONS & OTHER EXPENSES

LINE NO.	DATA REQUEST RESPONSE	DESCRIPTION	[A] COMPANY AS FILED	[B] STAFF ADJUSTMENTS	[C] STAFF AS ADJUSTED
1	CSB 1-34	Dues to Grand Canyon Electric Coop Assoc.	$ 130,697	$ (16,246)	$ 114,451
2	CSB 1-41	Dues for social and service clubs	$ 5,102	$ (5,102)	$ -
3	CSB 1-41	Memberships to Industry Associations	$ 44,880	$ (21,366)	$ 23,515
4	CSB 1-41	Charitable contributions	$ 51,876	$ (51,876)	$ -
5	CSB 1-41	Sponsorships	$ 93,461	$ (93,461)	$ -
6	CSB 1-41	Gifts, flowers, and awards	$ 42,260	$ (42,260)	$ -
7	CSB 1-41	Food and beverages	$ 29,442	$ (7,826)	$ 21,616
8	CSB 1-41	Luncheons and dinners	$ 39,147	$ (39,147)	$ -
9	CSB 1-41	Employee parties, picnics, or similar events	$ 35,120	$ (35,120)	$ -
10	CSB 1-41	Entertainment	$ 2,464	$ (2,464)	$ -
11	CSB 2-25	Advertising	$ 260,059	$ (159,921)	$ 100,138
11		TOTAL	$ 343,752	**$ (298,622)**	$ 45,130

References:

Column A: Cooperative Data Request Response CSB 1-34, 1-41, 2-25
Column B: Testimony, CSB
Column C: Column [A] + Column [B]

Sulphur Springs Valley Electric Cooperative
Docket No. E-01575A-08-0328
Test Year Ended December 31, 2007

OPERATING MARGIN ADJUSTMENT NO. 10 - INCENTIVE PAY

		[A]	[B]	[C]
LINE NO.	**DESCRIPTION**	**COMPANY AS FILED**	**STAFF ADJUSTMENTS**	**STAFF AS ADJUSTED**
1	Transmission Operation and Maint	$ 307	$ (307)	$ -
2	Distribution - Operations	$ 19,028	$ (19,028)	$ -
3	Distribution - Maintenance	$ 5,733	$ (5,733)	$ -
4	Consumer Accounting	$ 6,661	$ (6,661)	$ -
5	Customer Service	$ 1,625	$ (1,625)	$ -
6	Sales	$ 304	$ (304)	$ -
7	Administrative and General	$ 11,400	$ (11,400)	$ -
8		$ 45,058	$ (45,058)	$ -
9				
10				

		[D]	[E]	[G]	[H]	[I]	[J]
11							
12							**Incentive**
13			Employee			Percent	**Pay**
14		Payroll	Benefits	Payroll Tax	Total	to Total	**$ 45,058**
15	Trans Oper & Maint	$ 5,603	$ 882	$ 479	$ 6,964	0.68%	**$ 307**
16	Distr - Operations	$ 346,904	$ 54,856	$ 29,492	$ 431,251	42.23%	**$ 19,028**
17	Distr - Maintenance	$ 104,429	$ 16,369	$ 9,146	$ 129,945	12.72%	**$ 5,733**
18	Consumer Accounting	$ 121,096	$ 19,395	$ 10,478	$ 150,970	14.78%	**$ 6,661**
19	Customer Service	$ 29,528	$ 4,715	$ 2,583	$ 36,825	3.61%	**$ 1,625**
20	Sales	$ 5,483	$ 910	$ 486	$ 6,880	0.67%	**$ 304**
21	Admin and Gen	$ 207,063	$ 33,442	$ 17,867	$ 258,372	25.30%	**$ 11,400**
22		$ 820,106	$ 130,570	$ 70,531	$ 1,021,207	100.00%	**$ 45,058**

References:

Column A: Schedule CSB-19, Column J
Column B: Testimony, CSB
Column C: Column [A] + Column [B]

Sulphur Springs Valley Electric Cooperative
Docket No. E-01575A-08-0328
Test Year Ended December 31, 2007

OPERATING INCOME ADJUSTMENT NO. 11 - INTEREST EXP ON LONG-TERM DEBT

LINE NO.	DESCRIPTION	[A] COMPANY AS FILED	[B] STAFF ADJUSTMENTS	[C] STAFF AS ADJUSTED
1	Interest Expense on Long-term Debt	$ 6,994,249	$ (426,301)	$ 6,567,948
2				
3				

LINE NO.		Principal Per Company	Difference	Principal Per Staff	Interest Rate	Interest
6	CFC Notes	$ 7,580,857	$ -	$ 7,580,857	6.99%	$ 529,902
7	CFC Notes	$ 223,130	$ -	$ 223,130	5.69%	$ 12,696
8	CFC Notes	$ 6,679,114	$ -	$ 6,679,114	6.19%	$ 413,437
9	CFC Notes	$ 1,094,315	$ -	$ 1,094,315	5.44%	$ 59,531
10	CFC Notes	$ 4,505,110	$ -	$ 4,505,110	4.90%	$ 220,750
11	CFC Notes	$ 3,736,739	$ -	$ 3,736,739	4.60%	$ 171,890
12	CFC Notes	$ 4,704,874	$ -	$ 4,704,874	4.65%	$ 218,777
13	CFC Notes	$ 6,940,043	$ -	$ 6,940,043	5.30%	$ 367,822
14	CFC Notes	$ 8,883,720	$ -	$ 8,883,720	6.39%	$ 567,670
15	CFC Notes	$ 248,343	$ -	$ 248,343	3.84%	$ 9,536
16	CFC Notes	$ 484,009	$ -	$ 484,009	4.14%	$ 20,038
17	CFC Notes	$ 636,296	$ -	$ 636,296	4.39%	$ 27,933
18	CFC Notes	$ 784,238	$ -	$ 784,238	4.64%	$ 36,389
19	CFC Notes	$ 890,391	$ -	$ 890,391	4.84%	$ 43,095
20	CFC Notes	$ 962,025	$ -	$ 962,025	5.04%	$ 48,486
21	CFC Notes	$ 1,061,492	$ -	$ 1,061,492	5.09%	$ 54,030
22	CFC Notes	$ 2,059,876	$ -	$ 2,059,876	5.19%	$ 106,908
23	CFC Notes	$ 6,811,488	$ -	$ 6,811,488	5.24%	$ 356,922
24	CFC Notes	$ 6,511,760	$ -	$ 6,511,760	5.29%	$ 344,472
25	CFC Notes	$ 5,779,352	$ -	$ 5,779,352	5.59%	$ 323,066
26	CFC Notes	$ 5,881,037	$ -	$ 5,881,037	6.34%	$ 372,858
27	CFC Notes	$ 8,410,398	$ -	$ 8,410,398	6.59%	$ 554,245
28	CFC Notes	$ 2,976,264	$ -	$ 2,976,264	6.54%	$ 194,648
29	CFC Notes	$ 9,915,144	$ -	$ 9,915,144	6.09%	$ 603,832
30	CFC Notes	$ 2,000,000	$ -	$ 2,000,000	4.90%	$ 98,000
31	CFC Notes	$ 67,666	$ -	$ 67,666	4.90%	$ 3,316
32	CFC Notes	$ 8,000,000	$ -	$ 8,000,000	4.40%	$ 352,000
33	CFC Notes	$ 18,000,000	$ (8,700,000)	$ 9,300,000	4.90%	$ 455,700
34		$ 125,827,680	$ (8,700,000)	$ 117,127,680		$ 6,567,948

References:
Column A: Cooperative Schedule A-1.0, A-14.0
Column B: Testimony, CSB; Data Request Response STF 8.22
Column C: Column [A] + Column [B]

Sulphur Springs Valley Electric Cooperative
Docket No. E-01575A-08-0328
Test Year Ended December 31, 2007

Schedule CSB-21

OPERATING MARGIN ADJUSTMENT NO. 12 - CAPITAL CREDITS

LINE NO.	DESCRIPTION	[A] COMPANY AS FILED	[B] STAFF ADJUSTMENTS	[C] STAFF AS ADJUSTED
1	G&T Capital Credits	$ 2,592,402	$ (2,592,402)	$ -
2	Other Capital Credits	518,101	(130,414)	387,687
3		$ 3,110,503	$ (2,722,816)	$ 387,687
4				
5				
6				Cash
7				Capital Credits
8				CSB 3.16
9	G&T Capital Credits - AEPCO			$ -
10	Other Capital Credits - CFC			375,754
11	Other Capital Credits - NISC			60
12	Other Capital Credits - NRTC			3,823
13	Other Capital Credits - Federated Rural Insurance			6,041
14	Other Capital Credits - CRC			2,009
15				$ 387,687

References:

Column A: Cooperative Schedule A-1
Column B: Testimony, CSB; CSB 3.15, CSB 3.16
Column C: Column [A] + Column [B]

EXHIBIT
ALL-STATE LEGAL®
S-7
admitted

BEFORE THE ARIZONA CORPORATION COMMISSION

KRISTIN K. MAYES
Chairman
GARY PIERCE
Commissioner
SANDRA D. KENNEDY
Commissioner
PAUL NEWMAN
Commissioner
BOB STUMP
Commissioner

IN THE MATTER OF THE APPLICATION OF SULPHUR SPRINGS VALLEY ELECTRIC COOPERATIVE, INC. FOR A HEARING TO DETERMINE THE FAIR VALUE OF ITS PROPERTY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RETURN THEREON, TO APPROVE RATES DESIGNED TO DEVELOP SUCH RETURN AND FOR RELATED APPROVALS.	DOCKET NO. E-01575A-08-0328

SURREBUTTAL

TESTIMONY

OF

CRYSTAL S. BROWN

PUBLIC UTILITIES ANALYST V

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

APRIL 3, 2009

TABLE OF CONTENTS

SCHEDULES

EXECUTIVE SUMMARY
SULPHUR SPRINGS VALLEY ELECTRIC
COOPERATIVE, INC.
DOCKET NO. E-01575A-08-0328

Staff recommends total annual revenues of $100,420,597 resulting in a $15,365,515 operating margin or 11.56 percent rate of return on a $132,886,202 rate base. Staff's Surrebuttal testimony responds to Sulphur Spring's Rebuttal testimony on the following issues:

Operating Income:

a. 2008 Fort Huachuca Margin Increase
b. Employee Payroll, Benefits, and Payroll Taxes
c. Charitable Contributions and Other Expenses
d. Incentive Pay
e. Rate Case Expense
f. Debt Service Coverage Ratio
g. Equity Capitalization

INTRODUCTION

Q. Please state your name, occupation, and business address.

A. My name is Crystal S. Brown. I am a Public Utilities Analyst V employed by the Arizona Corporation Commission ("ACC" or "Commission") in the Utilities Division ("Staff"). My business address is 1200 West Washington Street, Phoenix, Arizona 85007.

Q. Are you the same Crystal S. Brown who filed direct testimony in this case?

A. Yes.

PURPOSE OF SURREBUTTAL TESTIMONY

Q. What is the purpose of your surrebuttal testimony in this proceeding?

A. The purpose of my surrebuttal testimony in this proceeding is to respond, on behalf of Staff, to the rebuttal testimony of Mr. David Hedrick who represents Sulphur Springs Valley Electric Cooperative, Inc. ("Sulphur Springs" or "Cooperative").

Q. What issues will you address?

A. I will address the issues listed below that are discussed in the rebuttal testimony of Sulphur Springs' witness Mr. David Hedrick:

Operating Income:

a. 2008 Fort Huachuca Margin Increase
b. Employee Payroll, Benefits, and Payroll Taxes
c. Charitable Contributions and Other Expenses
d. Incentive Pay
e. Rate Case Expense
f. Debt Service Coverage Ratio
g. Equity Capitalization

Q. What is Staff's recommended revenue?

A. Staff recommends total annual revenues of $100,420,597 resulting in a $15,365,515 operating margin or 11.56 percent rate of return on a $132,886,202 rate base. Staff's rate of return is not a predetermined number derived from a cost of capital analysis. Rather, because of the not-for-profit nature of the Cooperative, Staff used a cash flow analysis to set the revenue, which in turn, produced the 11.56 percent rate of return.

Operating Margin

Operating Margin – 2008 Fort Huachuca Contract Margin Increase

Q. Has Staff reviewed the Cooperative's rebuttal testimony concerning the 2008 Fort Huachuca Contract Margin Increase?

A. Yes.

Q. In recognition of the new information provided by the Cooperative in its rebuttal testimony, is Staff making any changes to its recommendation?

A. Yes. Staff is removing its adjustment to reflect the 2008 Fort Huachuca contract margin increase in test year revenues.

Q. What is Staff's surrebuttal recommendation?

A. Staff's surrebuttal recommendation reduces revenues by $918,806 as shown in Surrebuttal Schedule CSB-12.

Operating Margin – Employee Payroll, Benefits, and Payroll Taxes

Q. Please summarize Staff's recommendation concerning Employee Payroll, Benefits, and Payroll Taxes.

A. Staff recommends removing $523,570 in payroll expense for employees hired after the test year.

Q. What are the Cooperative's reasons for continuing to request recovery of expenses incurred after the test year?

A. The Cooperative's reasons can be summarized into two arguments as follows:

a. Post-Test Year ("PTY") Payroll Level Is Known, Measurable, and Continuing: The actual net increase in the number of employees hired after the test year is ten. The payroll level is representative of the known, measurable, and continuing level of payroll expense.

b. Historical Data Support an Increase in Employees: Sulphur Springs provides historical growth statistics to support the payroll costs of the ten employees. The Cooperative claims that the growth in the number of employees has been reasonable and necessary in order to provide services.

Q. Does Staff agree with any of the Cooperative's arguments?

A. No, Staff does not. Staff will address each of the Cooperative's arguments separately.

<u>Known, Measurable, and Continuing</u>

Q. Is it appropriate to reflect PTY payroll expenses simply because the amounts are "known, measurable, and continuing"?

A. No, it is not. The Cooperative chose a 2007 historical test year. Reflecting the ten additional employees hired in 2008 simply because the costs are "known, measurable, and continuing" is not appropriate because a PTY adjustment, by definition, is mismatched with the revenues, expenses and rate base components of the test year.

Q. What is the Arizona Administrative Code's definition of "test year"?

A. R14-2-103 (p) of the Administrative Code defines "test year" as follows:

> *"Test Year - the 1-year historical period used in determining rate base, operating income and rate of return. The end of the test year shall be the most recent practical date available before filing."*

Q. When is it appropriate to make pro forma adjustments to historical test year results?

A. The Administrative Code states that pro forma adjustments are:

> *"adjustments to actual test year results to obtain a normal or more realistic relationship between revenues, expenses and rate base."*

Therefore, it would be appropriate to make pro forma adjustments to test year actual results when those results are not normal or when it would provide a more realistic relationship between revenues, expenses, and rate base.

Q. Was the Cooperative's number of employees low during the test year?

A. No, the number of employees was not abnormally low during the test year. In data request CSB 1-18, Staff requested the following information:

> *State all major service objectives and indicate any areas where service levels or quality were not met in the Test Year or within the two prior years. If service or quality levels were not met, please provide documentation.*

The Cooperative did not indicate any problems with service or quality levels. Therefore, the number of employees was sufficient to provide adequate service.

Q. Did the Cooperative have any studies documenting its need for the PTY employees?

A. No, it did not. Staff asked for studies that could indicate the need for additional employees in data request CSB 2-21 (c) as follows:

> *Please provide the following information:*
> *(c) Studies documenting inadequate service levels caused by not having enough employees to perform the work.*

The Cooperative indicated that it had no such studies.

Q. Is the net impact of the 2008 payroll expense on rates "known and measurable" given that offsetting amounts in 2008 were not considered?

A. No, the net impact is not known and measurable. Matching is one of the most fundamental principles of accounting and rate making. When revenues and expenses are not matched to the same accounting period, so much pertinent information remains unknown, unmeasurable, and unconsidered that the meaning of and the usefulness of calculating operating income for purposes of setting rates becomes distorted.

Q. In regards to its requested ten PTY employees, did the Cooperative make a pro forma adjustment to reduce the test year number of over-time hours and expense?

A. No, it did not. This would be an appropriate adjustment if the Cooperative claims that its test year level of employees had to work over-time to perform work that it anticipates will be performed by the ten PTY employees.

Historical Data Support an Increase in Employees

Q. Does the historical data provided by the Cooperative support an increase to the test year actual number of employees?

A. No, it does not. The data provided shows, that as the Cooperative grows, it incurs additional costs, such as plant and employees, to serve that growth. The Cooperative requested and the Commission approved, in Decision No. 70027, dated December 4, 2007, a $70.78 million loan from the National Rural Utilities Cooperative Finance Corporation ("CFC"). The major reason for the loan was to fund the increased capital expenditures necessary to construct new facilities to serve growth. Additional employees are needed to operate and maintain the new plant construction. The cost of these new employees to serve growth should not be borne by test year customers.

Q. What type of historical data would support an increase in test year employees?

A. The type of historical data needed to support an increase in test year employees would be data that establishes a physical performance standard such as the number of labor hours needed to inspect or test overhead distribution lines and poles for the test year and an analysis showing that the test year employee level was inadequate to perform the work.

Q. Does the Cooperative's analysis to include PTY employees consider any relationship between PTY plant, customers, revenues, and expenses?

A. No it does not. In 2008, the Cooperative installed an additional 31 miles of overhead distribution lines and added about 400 customers. For each additional kilowatt-hour ("kWh") that the Cooperative sells to these 400 customers, more revenue will be available to pay for expenses such as purchased power and employees needed to serve them.

Q. Please summarize Staff's surrebuttal position.

A. Staff's position has not changed. The Cooperative did not indicate any problems with service or quality levels during the 2007 historical test year. The number of employees was not abnormally low during the test year as the Cooperative could not provide evidence such as studies or similar type of evidence documenting service or quality problems due to an inadequate level of employees. The ten PTY employees hired in 2008 were needed to serve growth that occurred in 2008 and for future years. The data provided shows that as the Cooperative grows, it incurs additional costs, such as plant and employees, to serve that growth. The cost of these new employees to serve growth should not be borne by test year customers.

Operating Margin – Charitable Contributions and Other Expenses

Q. Has Staff reviewed the Cooperative's rebuttal testimony concerning Charitable Contributions and Other Expenses?

A. Yes.

Q. Does Staff agree with the Cooperative's arguments?

A. No. The Commission, in Decision No. 58358, does not provide for automatic recovery of such costs.

Q. Is Staff recommending that the Cooperative cease charitable and similar types of expenses?

A. No.

Q. Have other cooperatives regulated by this Commission adopted Staff's recommendation to recognize charitable contributions and other expenses below the line?

A. Yes, Arizona Electric Power Cooperative, in Decision No. 68071, dated August 17, 2005.

Q. Please summarize Staff's surrebuttal recommendation concerning Charitable Contributions and Other Expenses.

A. Staff's recommendation has not changed. Contributions and donations are voluntary costs and, therefore, not needed in the provision of service. Further, Decision No. 58358 does not provide for automatic recovery of such costs.

Operating Margin – Incentive Pay

Q. Has Staff reviewed the Cooperative's rebuttal testimony concerning incentive pay?

A. Yes.

Q. Does Staff agree with the Cooperative's arguments?

A. No.

Q. Is Staff recommending that the Cooperative cease incentive pay expense?

A. No.

Q. Please summarize Staff's surrebuttal position concerning incentive pay.

A. Staff's recommendation has not changed. Sulphur Springs pays its employees competitive salary, wage and benefits packages with regular annual wage increases. These costs are designed to compensate the employees to perform work that will enable the Cooperative to provide safe and reliable service. Therefore, the cost of the employees' base salaries and wages is a required cost. The incentive pay is an optional cost and, therefore, should be not be recovered through rates. Staff is not recommending that the Cooperative cease from incurring incentive pay expenses, but rather that these expenses be paid from the approximately $8.8 million in internally generated cash flow as shown on Surrebuttal Schedule CSB-22.

Operating Margin – Rate Case Expense

Q. Has Staff reviewed the Cooperative's rebuttal testimony concerning rate case expense?

A. Yes.

Q. By what amount is the Cooperative proposing to increase rate case expense?

A. The Cooperative is proposing to increase rate case expense by $59,522 per year, from $20,000 requested in its direct testimony to $79,522 requested in its rebuttal testimony.

Q. What types of costs are appropriate for rate case expense?

A. Actual and reasonable costs are appropriate for rate case expense.

Q. Does all of the $79,522 in rate case expense represent actual costs?

A. No, a portion of the cost is based on estimates as anticipated costs for the Cooperative's rejoinder testimony, hearing, and open meeting are included in the amount.

Q. Does Staff agree that the proposed $79,522 is reasonable?

A. No, Staff does not agree. Appropriately managing the rate case process involves (1) determining a rate case budget (2) evaluating the strength of the issues in the case and (3) assessing the marginal benefit of each cost, such as but not limited to, issues, experts, consultants, and attorneys.

Q. Did the Cooperative develop a budget, evaluate strengths, and assess marginal benefits of costs in the development of its requested rate case expense?

A. It provided no evidence in support of such efforts. Staff determined through the Cooperative's response to data request CSB 1.49, that the Cooperative did not prepare a budget that itemized anticipated costs. A detailed budget is a management tool that helps control costs. Actual costs are compared to budgeted costs and any variances are investigated in order to determine necessary management control action. Further, Staff determined through the Cooperative's response to data request CSB 1.48 that it did not go through a process of evaluating the strength and assessing the marginal benefit of each cost. Lack of a budget and careful analysis of costs is indicative of lack of control over costs and of poor planning.

Q. Please summarize Staff's recommendation.

A. Staff's position has not changed. The $59,522 increase represents a quadrupling of the rate case expense. The amount is excessive and unreasonable because it was caused by a lack of control over costs. Recognizing the costs below the line is not harmful because the customers of the Cooperative are also the owners of the Cooperative.

DEBT SERVICE COVERAGE RATIO ("DSC")

Q. Has Staff reviewed the Cooperative's rebuttal testimony concerning DSC?

A. Yes.

Q. Has Staff made any changes to its recommended increase in gross revenue?

A. Yes, Staff increased its recommended increase in gross revenue by $1,241,821, from $6,353,795 in its direct testimony to $7,595,616 in its surrebuttal testimony.

Q. Did Staff prepare a schedule showing the cash flow resulting from Staff's recommendation?

A. Yes, Staff's cash flow is presented on Surrebuttal Schedule CSB-22.

Q. How much cash flow would result from Staff's recommended rates?

A. Before debt payments, the Cooperative would have $22.9 million available. After debt payments, the Cooperative would have $8.8 million available.

Q. What times interest earned ratio ("TIER") and DSC result from Staff's recommendation?

A. Staff's recommended level of increase results in a 2.34 operating TIER and a 2.12 DSC. Staff's recommended DSC of 2.12 promotes the financial soundness of the Cooperative and is adequate, under efficient and economical management, to maintain and support its credit and enable it to obtain the money necessary to provide safe and reliable electric service.

CAPITAL STRUCTURE

Q. Did Staff review the Cooperative's rebuttal testimony concerning capital structure?

A. Yes.

Q. Does Staff agree that the year 2016 is a reasonable period in which to obtain a 30 percent equity to long-term debt capitalization ratio?

A. Yes.

Q. How does Staff's recommended increase in gross revenue enable the Cooperative to obtain a 30 percent equity capitalization ratio by 2016?

A. Staff has recommended an operating margin increase of $322,715, from $15,042,800 in Staff's direct testimony to $15,365,515 in Staff's surrebuttal testimony. This additional operating margin will increase the Cooperative's equity. Further, the Cooperative can utilize approximately $3 million of the $8.8 million available to lower the amount of its anticipated long-term debt. Further, Staff assumes that the Cooperative's level of long-term debt will begin to fall by at least 10 percent per year after the Commission approved $70.78 million has been fully drawn which is projected to be in the year 2013. This is because the nation is in a recession and may take several years to recover. There is slowed job growth, job losses, and rising unemployment. New home construction is down and is not expected to continue at the same rate.

Q. Did Staff prepare a schedule showing its equity and long-term debt projections?

A. Yes. Staff's equity and long-term debt projections are shown on Schedule CSB-23.

Q. Does this conclude Staff's surrebuttal testimony?

A. Yes, it does.

Sulphur Springs Valley Electric Cooperative
Docket No. E-01575A-08-0328
Test Year Ended December 31, 2007

Surrebuttal Schedule CSB-1

REVENUE REQUIREMENT

LINE NO.	DESCRIPTION		[A] COMPANY ORIGINAL COST		[B] STAFF ORIGINAL COST
1	Adjusted Operating Margin (Loss)	$	6,251,098	$	7,770,199
2	Depreciation and Amortization	$	7,574,650	$	7,574,650
3	Income Tax Expense		-		-
4	Long-term Interest Expense	$	6,994,249	$	6,567,948
5	Principal Repayment	$	4,269,396	$	4,269,396
6a	**Recommended Increase in Operating Revenue**	$	10,881,590	**$**	**7,595,316**
6b	**Percent Increase (Line 6a / Line 7) - Per Staff**		N/A		**8.18%**
6c	Percent Increase (Line 6a / $92,613,559) - Per Cooperative		11.75%		N/A
7	Adjusted Test Year Operating Revenue	$	92,613,559	$	92,825,281
8	**Recommended Annual Operating Revenue**	$	103,495,149	**$**	**100,420,597**
9a	**Recommended Operating Margin**	$	17,132,688	**$**	**15,365,515**
9b	Recommended Net Margin	$	12,990,628	$	8,259,260
10a	**Recommended Operating TIER (L3+L9)/L4 - Per Staff**		N/A		**2.34**
10b	Recommended Net TIER - Per Cooperative		2.86		N/A
11a	**Recommended DSC (L2+L3+L9a)/(L4+L5) - Per Staff**		N/A		**2.12**
11b	Recommended DSC (L2+L4+L9b)/(L4+L5) - Per Cooperative		2.45		N/A
12	**Adjusted Rate Base**	$	136,903,293	**$**	**132,886,202**
13	Rate of Return (L9a / L12)		12.51%		11.56%

References:
Column [A]: Company Schedules A-1, C-1, C-3
Column [B]: Staff Schedules CSB-2, CSB-11, Testimony

Sulphur Springs Valley Electric Cooperative
Docket No. E-01575A-08-0328
Test Year Ended December 31, 2007

Surrebuttal Schedule CSB-2

RATE BASE - ORIGINAL COST

LINE NO.		[A] COMPANY AS FILED	[B] STAFF ADJUSTMENTS	[C] STAFF AS ADJUSTED
1	Plant in Service	$ 212,732,380	$ -	$ 212,732,380
2	Less: Acc Depreciation & Amortization	(72,528,240)	190,405	(72,337,835)
3	Net Plant in Service	$ 140,204,140	$ 190,405	$ 140,394,545
	LESS:			
4	Consumer Deposits	$ (1,506,543)	$ (169,231)	$ (1,675,774)
5	Consumer Advances	$ (4,624,248)	$ (290,367)	$ (4,914,615)
6	Deferred Credits	$ -	$ (917,955)	$ (917,955)
7	Total	(6,130,791)	(1,377,552)	(7,508,343)
	ADD:			
8	Cash Working Capital	$ -	$ -	$ -
9	Materials and Supplies	$ 2,157,124	$ (2,157,124)	$ -
10	Prepayments	$ 672,820	$ (672,820)	$ -
11	Total	$ 2,829,944	$ (2,829,944)	$ -
12	**Total Rate Base**	$ 136,903,293	$ (4,017,091)	$ 132,886,202

References:
Column [A], Cooperative Schedule B-1
Column [B]: Schedules CSB-2 through CSB-7
Column [C]: Column [A] + Column [B]

Sulphur Springs Valley Electric Cooperative
Docket No. E-01575A-08-0328
Test Year Ended December 31, 2007

SUMMARY OF RATE BASE ADJUSTMENTS

LINE NO.	Acct. No.	DESCRIPTION	[A] COOPERATIVE AS FILED	[B] Accumulated Depreciation AMR's ADJ No.1 Ref: Sch CSB-4	[C] Consumer Deposits and Advances ADJ No. 2 Ref: Sch CSB-5	[D] Deferred Credits ADJ No. 3 Ref: Sch CSB-6	[E] Materials and Prepayments ADJ No. 4 Ref: Sch CSB-7	[F] STAFF ADJUSTED
		PLANT IN SERVICE:						
1	303	Intangible Plant	$ 46,500	$ -	$ -	$ -	$ -	$ 46,500
2	350	Transmission Plant - Land and Land Rights	$ 633,768	$ -	$ -	$ -	$ -	$ 633,768
3	353	Transmission Plant - Station Equipment	$ 933,201	$ -	$ -	$ -	$ -	$ 933,201
4	355	Transmission Plant - Poles and Fixtures	$ 2,774,629	$ -	$ -	$ -	$ -	$ 2,774,629
5	356	Transmission Plant - OH Conductors	$ 5,630,063	$ -	$ -	$ -	$ -	$ 5,630,063
6	360	Distribution Plant - Land and Land Rights	$ 124,706	$ -	$ -	$ -	$ -	$ 124,706
7	361	Distribution Plant - Structures and Improvements	$ 5,191	$ -	$ -	$ -	$ -	$ 5,191
8	362	Distribution Plant - Substation Equipment	$ 18,024,631	$ -	$ -	$ -	$ -	$ 18,024,631
9	364	Distribution Plant - Poles, Towers, and Fixtures	$ 34,444,295	$ -	$ -	$ -	$ -	$ 34,444,295
10	365	Distribution Plant - Conductors and Devices	$ 22,877,936	$ -	$ -	$ -	$ -	$ 22,877,936
11	366	Distribution Plant - Underground Conduit	$ 16,753,223	$ -	$ -	$ -	$ -	$ 16,753,223
12	367	Distribution Plant - Underground Conductors	$ 26,203,285	$ -	$ -	$ -	$ -	$ 26,203,285
13	368	Distribution Plant - Transformers	$ 40,732,770	$ -	$ -	$ -	$ -	$ 40,732,770
14	369	Distribution Plant - Services	$ 8,532,859	$ -	$ -	$ -	$ -	$ 8,532,859
15	370	Distribution Plant - Meters	$ 9,336,411	$ -	$ -	$ -	$ -	$ 9,336,411
16	371	Distribution Plant - Install. On Customers Premises	$ 1,316,138	$ -	$ -	$ -	$ -	$ 1,316,138
17	373	Distribution Plant - Street Lighting and Signal Syst	$ 2,135,425	$ -	$ -	$ -	$ -	$ 2,135,425
18	389	General Plant - Land and Land Rights	$ 807,670	$ -	$ -	$ -	$ -	$ 807,670
19	390	General Plant - Structures and Improvements	$ 7,019,401	$ -	$ -	$ -	$ -	$ 7,019,401
20	391	General Plant - Office Furniture and Equipment	$ 3,231,257	$ -	$ -	$ -	$ -	$ 3,231,257
21	392	General Plant - Transportation Equipment	$ 4,353,642	$ -	$ -	$ -	$ -	$ 4,353,642
22	393	General Plant - Stores Equipment	$ 293,929	$ -	$ -	$ -	$ -	$ 293,929
23	394	General Plant - Tools, Shop, & Garage Equipment	$ 1,368,880	$ -	$ -	$ -	$ -	$ 1,368,880
24	395	General Plant - Laboratory Equipment	$ 774,153	$ -	$ -	$ -	$ -	$ 774,153
25	396	General Plant - Power Operated Equipment	$ 7,085,730	$ -	$ -	$ -	$ -	$ 7,085,730
26	397	General Plant - Communications Equipment	$ 903,184	$ -	$ -	$ -	$ -	$ 903,184
27	398	General Plant - Miscellaneous	$ (3,682,314)	$ -	$ -	$ -	$ -	$ (3,682,314)
28	399	General Plant - Contributed dollars	$ 71,817	$ -	$ -	$ -	$ -	$ 71,817
29		Total Plant in Service	$ 212,732,380	$ -	$ -	$ -	$ -	$ 212,732,380
30		Less: Accumulated Depreciation	$ (72,528,240)	$ 190,405	$ -	$ -	$ -	$ (72,337,835)
31		Less: Accumulated Amortization	-	-	-	-	-	-
32		Total Accumulated Depreciation & Amortization	$ (72,528,240)	$ 190,405	$ -	$ -	$ -	$ (72,337,835)
33		Net Plant in Service	$ 140,204,140	$ 190,405	$ -	$ -	$ -	$ 140,394,545
		LESS:						
34		Consumer Deposits	$ (1,506,543)	$ -	$ (169,231)	$ -	$ -	$ (1,675,774)
35		Consumer Advances	$ (4,624,248)	$ -	$ (290,367)	$ -	$ -	$ (4,914,615)
36		Deferred Credits	$ -	$ -	$ -	$ (917,955)	$ -	$ (917,955)
37		Total	$ (6,130,791)	$ -	$ (459,598)	$ (917,955)	$ -	$ (7,508,343)
		ADD:						
38		Cash Working Capital	$ -	$ -	$ -	$ -	$ -	$ -
39		Materials and Supplies	$ 2,157,124	$ -	$ -	$ -	$ (2,157,124)	$ -
40		Prepayments	$ 672,820	$ -	$ -	$ -	$ (672,820)	$ -
41		Total	$ 2,829,944	$ -	$ -	$ -	$ (2,829,944)	$ -
42		**Total Rate Base**	$ 136,903,293	$ 190,405	$ (459,598)	$ (917,955)	$ (2,829,944)	$ 132,886,202

Sulphur Springs Valley Electric Cooperative
Docket No. E-01575A-08-0328
Test Year Ended December 31, 2007

Surrebuttal Schedule CSB-4

RATE BASE ADJUSTMENT NO. 1 - ACCUMULATED DEPRECIATION, AMR

LINE NO.	DESCRIPTION	[A] COMPANY AS FILED	[B] STAFF ADJUSTMENTS	[C] STAFF AS ADJUSTED
1	Accumulated Depreciation before Accelerated Depr	$ 72,337,835	$ (0)	$ 72,337,835
2	Accelerated Depreciation on AMR	190,405	(190,405)	-
3	Total	$ 72,528,240	$ (190,405)	$ 72,337,835

References:
Column [A]: Cooperative Schedules B-1.0
Column [B]: Testimony, CSB; Data Request Response CSB 3.11
Column [C]: Column [A] + Column [B]

Sulphur Springs Valley Electric Cooperative
Docket No. E-01575A-08-0328
Test Year Ended December 31, 2007

Surrebuttal Schedule CSB-5

RATE BASE ADJUSTMENT NO. 2 - CONSUMER DEPOSITS AND ADVANCES

		[A]	[B]	[C]
LINE NO.	DESCRIPTION	COMPANY AS FILED	STAFF ADJUSTMENTS	STAFF AS ADJUSTED
1	Consumer Deposits	$ 1,506,543	$ 169,231	$ 1,675,774
2	Consumer Advances	4,624,248	290,367	4,914,615
3	Total	$ 6,130,791	$ 459,598	$ 6,590,389

References:
Column [A]: Cooperative Schedules B-1.0
Column [B]: Column [C] + Column [A]
Column [C]: Testimony, CSB; Cooperative Schedule B-3.0

Sulphur Springs Valley Electric Cooperative
Docket No. E-01575A-08-0328
Test Year Ended December 31, 2007

Surrebuttal Schedule CSB-6

RATE BASE ADJUSTMENT NO. 3 - DEFERRED CREDITS

		[A]	[B]	[C]
LINE NO.	**DESCRIP DESCRIPTION**	**COMPANY AS FILED (Sch E-5)**	**STAFF ADJUSTMENTS**	**STAFF AS ADJUSTED**
1	Deferred Credits	$ -	$ 917,955	$ 917,955

Account Number			
252.10	Cost to remove temporary power structures	$ 32,464	
253.00	Poles attachments/joint use revenue	$ 251,979	
253.10	Line extension payments	$ 243,541	
253.26	Uncashed checks	$ 389,971	
		$ 917,955	**Total Deferred Credits Per Staff**
252.00	Consumer Advances for Construction	$ 4,914,615	Separate rate base deduction
253.25	Alternative engergy collections	$ 1,209,296	DSM costs
253.50	Over-collections of fuel adjustor	$ 1,585,042	Fuel adjustor collections
253.97	Fort Huachuca - Deferred Revenue	$ 5,314,977	Revenue billed but not received
	Total Staff Adjusted Deferred Credits	$ 13,941,885	Total Deferred Credits Per G/L

References:
Column [A]: Cooperative Schedule B-1.0
Column [B]: Testimony, CSB; Cooperative Schedule C-1.0, Data Request 2.3
Column [C]: Column [A] + Column [B]

Sulphur Springs Valley Electric Cooperative
Docket No. E-01575A-08-0328
Test Year Ended December 31, 2007

Surrebuttal Schedule CSB-7

RATE BASE ADJUSTMENT NO. 4 - WORKING CAPITAL

		[A]	[B]	[C]
LINE NO.	DESCRIPTION	COMPANY AS FILED	STAFF ADJUSTMENTS	STAFF AS ADJUSTED
1	Cash Working Capital	$ -	$ -	$ -
2	Materials and Supplies	$ 2,157,124	$ (2,157,124)	$ -
3	Prepayments	$ 672,820	$ (672,820)	$ -
4	**Total Working Capital**	**$ 2,829,944**	**$ (2,829,944)**	**$ -**

References:
Column [A]: Cooperative Schedules B-1.0 and B-3.0
Column [B]: Column [C] + Column [A]
Column [C]: Testimony, CSB

Surrebuttal Schedule CSB-8

Sulphur Springs Valley Electric Cooperative
Docket No. E-01575A-08-0328
Test Year Ended December 31, 2007

OPERATING MARGIN - TEST YEAR AND STAFF PROPOSED

Line No.	DESCRIPTION	[A] COMPANY TEST YEAR AS FILED	[B] STAFF TEST YEAR ADJUSTMENTS	[C] STAFF TEST YEAR AS ADJUSTED	[D] STAFF RECOMMENDED CHANGES	[E] STAFF RECOMMENDED
	REVENUES:					
1	Margin Revenue (Non-Base Cost of Power)	$ 30,530,901	$ 303,312	$ 30,834,213	$ 7,250,351	$ 38,084,564
2	Rounding	$ 3	$ -	$ 3		$ 3
3	Margin Revenue	$ 30,530,904	$ 303,312	$ 30,834,216	$ 7,250,351	$ 38,084,567
4						
5	Base Cost of Power Revenue	$ 47,167,753	$ 10,523,837	$ 57,691,590	$ -	$ 57,691,590
6	Wholesale Power Cost Adjustor (WPCA)	$ 10,523,837	$ (10,523,837)	$ -	$ -	$ -
7	Rounding	$ (3)	$ -	$ (3)	$ -	$ (3)
8	Base Cost of Power and Adjustor Revenue	$ 57,691,587	$ -	$ 57,691,587	$ -	$ 57,691,587
9						
10	**Total Revenue from Sales of Electricity**	**$ 88,222,491**	**$ 303,312**	**$ 88,525,803**	**$ 7,250,351**	**$ 95,776,154**
11	Other Revenues	$ 4,391,068	$ (91,590)	$ 4,299,478	$ 344,965	$ 4,644,443
12	2008 Ft Huachuca Margin	$ -	$ -	$ -	$ -	$ -
13	**Total Revenues**	**$ 92,613,559**	**$ 211,722**	**$ 92,825,281**	**$ 7,595,316**	**$ 100,420,597**
14						
15	*EXPENSES:*					
16	Purchased Power	$ 57,691,587	$ 0	$ 57,691,587	$ -	$ 57,691,587
17	Transmission Operation and Maintenance	$ 253,985	$ (1,354)	$ 252,631	$ -	$ 252,631
18	Distribution - Operations	$ 8,524,851	$ (155,438)	$ 8,369,413	$ -	$ 8,369,413
19	Distribution - Maintenance	$ 2,532,504	$ (47,196)	$ 2,485,308	$ -	$ 2,485,308
20	Consumer Accounting	$ 3,024,637	$ (54,014)	$ 2,970,623	$ -	$ 2,970,623
21	Customer Service	$ 680,691	$ (13,743)	$ 666,948	$ -	$ 666,948
22	Sales	$ 562,326	$ (3,831)	$ 558,495	$ -	$ 558,495
23	Administrative and General	$ 4,226,472	$ (1,031,803)	$ 3,194,669	$ -	$ 3,194,669
24	Depreciation and Amortization	$ 7,574,650	$ -	$ 7,574,650	$ -	$ 7,574,650
25	Taxes	$ 1,290,758	$ -	$ 1,290,758	$ -	$ 1,290,758
26	**Total Operating Expenses**	$ 86,362,461	$ (1,307,380)	$ 85,055,081	$ -	$ 85,055,081
27						
28	**Operating Margin Before Interest on L.T.- Debt**	$ 6,251,098	$ 1,519,101	$ 7,770,199	$ -	$ 15,365,515
29						
30	***INTEREST ON LONG-TERM DEBT & OTHER DEDUCTIONS***					
31	Interest on Long-term Debt	$ 6,994,249	$ (426,301)	$ 6,567,948	$ -	$ 6,567,948
32	Interest - Other	$ 366,551	$ -	$ 366,551	$ -	$ 366,551
33	Other Dedcutions	$ 171,756	$ -	$ 171,756	$ -	$ 171,756
34	**Total Interest & Other Deductions**	$ 7,532,556	$ (426,301)	$ 7,106,255	$ -	$ 7,106,255
35						
36	***MARGINS (LOSS) AFTER INTEREST EXPENSE***	$ (1,281,458)	$ 1,945,402	$ 663,944	$ -	$ 8,259,260
37						
38	***NON-OPERATING MARGINS***					
39	Interest Income	$ 141,825	$ -	$ 141,825	$ -	$ 141,825
40	Other Margins	$ 138,168	$ -	$ 138,168	$ -	$ 138,168
41	G&T Capital Credits	$ 2,592,402	$ (2,592,402)	$ -	$ -	$ -
42	Other Capital Credits	$ 518,101	$ (130,414)	$ 387,687	$ -	$ 387,687
43	**Total Non-Operating Margins**	$ 3,390,496	$ (2,722,816)	$ 667,680	$ -	$ 667,680
44						
45	***EXTRAORDINARY ITEMS***	$ -	$ -	$ -	$ -	$ -
46						
47	***NET MARGINS (LOSS)***	$ 2,109,038	$ (777,414)	$ 1,331,624	$ -	$ 8,926,940
48						
49						

50 References:
51 Column (A): Cooperative Schedule A
52 Column (B): Schedule CSB-9
53 Column (C): Column (A) + Column (B)
54 Column (D): Schedule CSB-1
55 Column (E): Column (C) + Column (D)

Sulphur Springs Valley Electric Cooperative
Docket No. E-01575A-08-0328
Test Year Ended December 31, 2007

SUMMARY OF OPERATING MARGIN ADJUSTMENTS - TEST YEAR

LINE NO.	DESCRIPTION	[A] COMPANY AS FILED	[B] ADJ #1 Revenue and Expense Annualizations Ref: Sch CSB-10	[C] ADJ #2 Miscellaneous Service Charge Revenue Ref: Sch CSB-11	[D] ADJ #3 2008 Fort Huachuca Margin Increase Ref: Sch CSB-12	[E] ADJ #4 Base Cost of Power and Wholesale Pwr Cost Adjustor Ref: Sch CSB-13	[F] ADJ #5 Demand Side Management Expenses Ref: Sch CSB-14	[G] ADJ #6 Employee Payroll, Benefits and Payroll Taxes Ref: Sch CSB-15	[H] ADJ #7 GDS Expenses Ref: Sch CSB-16
	REVENUES:								
1	Margin Revenue (Non-Base Cost of Power)	$ 30,530,901	$ 303,312	$ -	$ -	$ -	$ -	$ -	$ -
2	Rounding	3	-	-	-	-	-	-	-
3	Margin Revenue	$ 30,530,904	$ 303,312	$ -	$ -	$ -	$ -	$ -	$ -
4									
5	Base Cost of Power Revenue	$ 47,167,753	$ -	$ -	$ -	$ 10,523,837	$ -	$ -	$ -
6	Wholesale Power Cost Adjustor (WPCA)	10,523,837	-	-	-	(10,523,837)	-	-	-
7	Rounding	(3)	-	-	-	-	-	-	-
8	Base Cost of Power and Adjustor Revenue	$ 57,691,587	$ -	$ -	$ -	$ -	$ -	$ -	$ -
9									
10	Total Revenue from Sales of Electricity	$ 88,222,491	$ 303,312	$ -	$ -	$ -	$ -	$ -	$ -
11	Other Revenues	$ 4,391,068	$ -	$ (91,590)	$ -	$ -	$ -	$ -	$ -
12	2008 Ft Huachuca Margin	-	-	-	-	-	-	-	-
13	**Total Revenues**	**$ 92,613,559**	**$ 303,312**	**$ (91,590)**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
14									
15	*OPERATING EXPENSES:*								
16	Purchased Power	$ 57,691,587	$ -	$ -	$ -	$ 0	$ -	$ -	$ -
17	Transmission Operation and Maintenance	253,985	2,523	-	-	-	-	(3,570)	-
18	Distribution - Operations	8,524,851	84,691		-	-	-	(221,101)	-
19	Distribution - Maintenance	2,532,504	25,159	-	-	-	-	(66,622)	-
20	Consumer Accounting	3,024,637	30,049	-	-	-	-	(77,402)	-
21	Customer Service	680,691	6,762	-	-	-	-	(18,880)	-
22	Sales	562,326	-	-	-	-	-	(3,527)	-
23	Administrative and General	4,226,472	-		-	-	(484,996)	(132,467)	(51,427)
24	Depreciation and Amortization	7,574,650	-	-	-	-	-	-	-
25	Taxes	1,290,758	-	-	-	-	-	-	-
26	**Total Operating Expenses**	$ 86,362,461	$ 149,184	$ -	$ -	$ 0	$ (484,996)	$ (523,570)	$ (51,427)
27									
28	**Operating Margin Before Interest on L.T.- Debt**	**$ 6,251,098**	**$ 154,128**	**$ (91,590)**	**$ -**	**$ (0)**	**$ 484,996**	**$ 523,570**	**$ 51,427**
29									
30	*INTEREST ON LONG-TERM DEBT & OTHER DEDUCTIONS*								
31	Interest on Long-term Debt	$ 6,994,249	$ -	$ -	$ -	$ -	$ -	$ -	$ -
32	Interest - Other	$ 366,551	-	-	-	-	-	-	-
33	Other Dedcutions	171,756	-	-	-	-	-	-	-
34	**Total Interest & Other Deductions**	$ 7,532,556	$ -	$ -	$ -	$ -	$ -	$ -	$ -
35									
36	***MARGINS (LOSS) AFTER INTEREST EXPENSE***	**$ (1,281,458)**	**$ 154,128**	**$ (91,590)**	**$ -**	**$ (0)**	**$ 484,996**	**$ 523,570**	**$ 51,427**
37									
38	*NON-OPERATING MARGINS*								
39	Interest Income	$ 141,825	$ -	$ -	$ -	$ -	$ -	$ -	$ -
40	Other Margins	$ 138,168							
41	G&T Capital Credits	$ 2,592,402							
42	Other Capital Credits	518,101	-	-	-	-	-	-	-
43	**Total Non-Operating Margins**	$ 3,390,496	$ -	$ -	$ -	$ -	$ -	$ -	$ -
44									
45	*EXTRAORDINARY ITEMS*	$ -	-	-	-	-	-	-	-
46									
47	*NET MARGINS (LOSS)*	$ 2,109,038	$ 154,128	$ (91,590)	$ -	$ (0)	$ 484,996	$ 523,570	$ 51,427

Sulphur Springs Valley Electric Cooperative
Docket No. E-01575A-08-0328
Test Year Ended December 31, 2007

LINE NO.	DESCRIPTION	[I] ADJ #8 Normalized Legal Expenses Ref: Sch CSB-17	[J] ADJ #9 Charitable Contributions and Other Expenses Ref: Sch CSB-18	[K] ADJ #10 Incentive Pay Ref: Sch CSB-19	[L] ADJ #11 Interest Expense on L.T. Debt Ref: Sch CSB-20	[M] ADJ #12 Capital Credits Ref: Sch CSB-21	[N] STAFF ADJUSTED
	REVENUES:						
1	Margin Revenue (Non-Base Cost of Power)	$ -	$ -	$ -	$ -	$ -	$ 30,834,213
2	Rounding	-	$ -	$ -	$ -	$ -	3
3	Margin Revenue	$ -					$ 30,834,216
4							
5	Base Cost of Power Revenue	$ -	$ -	$ -	$ -	$ -	$ 57,691,590
6	Wholesale Power Cost Adjustor (WPCA)	-	-	-	-	-	-
7	Rounding	-	-	-	-	-	(3)
8	Base Cost of Power Revenue	$ -	$ -	$ -	$ -	$ -	$ 57,691,587
9							
10	Total Revenue from Sales of Electricity	$ -	$ -	$ -	$ -	$ -	$ 88,525,803
11	Other Revenues	$ -	$ -	$ -	$ -	$ -	$ 4,299,478
12	2008 Ft Huachuca Margin	-	-	-	-	-	-
13	**Total Revenues**	$ -	$ -	$ -	$ -	$ -	$ 92,825,281
14							
15	***OPERATING EXPENSES:***						
16	Purchased Power	$ -	$ -	$ -	$ -	$ -	$ 57,691,587
17	Transmission Operation and Maintenance	-	-	(307)	-	-	252,631
18	Distribution - Operations	-	-	(19,028)	-	-	8,369,413
19	Distribution - Maintenance	-	-	(5,733)	-	-	2,485,308
20	Consumer Accounting	-	-	(6,661)	-	-	2,970,623
21	Customer Service	-	-	(1,625)	-	-	666,948
22	Sales	-	-	(304)	-	-	558,495
23	Administrative and General	(52,892)	(298,622)	(11,400)	-	-	3,194,669
24	Depreciation and Amortization	-	-	-	-	-	7,574,650
25	Taxes	-	-	-	-	-	1,290,758
26	**Total Operating Expenses**	$ (52,892)	$ (298,622)	$ (45,058)	$ -	$ -	$ 85,055,081
27							
28	**Operating Margin Before Interest on L.T.- Debt**	$ 52,892	$ 298,622	$ 45,058	$ -	$ -	$ 7,770,199
29							
30	***INTEREST ON LONG-TERM DEBT & OTHER DEDUCTIONS***						
31	Interest on Long-term Debt	$ -	$ -	$ -	$ (426,301)	$ -	$ 6,567,948
32	Interest - Other	-	-	-	-	-	366,551
33	Other Dedcutions	-	-	-	-	-	171,756
34	**Total Interest & Other Deductions**	$ -	$ -	$ -	$ (426,301)	$ -	$ 7,106,255
35							
36	***MARGINS (LOSS) AFTER INTERST EXPENSE***	$ 52,892	$ 298,622	$ 45,058	$ 426,301	$ -	$ 663,944
37							
38	***NON-OPERATING MARGINS***						
39	Interest Income	$ -	$ -	$ -	$ -	$ -	$ 141,825
40	Other Margins		-	-	-	-	138,168
41	G&T Capital Credits		-	-	-	(2,592,402)	-
42	Other Capital Credits	-	-	-	-	(130,414)	387,687
43	**Total Non-Operating Margins**	$ -	$ -	$ -	$ -	$ (2,722,816)	$ 667,680
44							
45	***EXTRAORDINARY ITEMS***	-	-	-		-	-
46							
47	***NET MARGINS (LOSS)***	$ 52,892	$ 298,622	$ 45,058	$ 426,301	$ (2,722,816)	$ 1,331,624

Sulphur Springs Valley Electric Cooperative
Docket No. E-01575A-08-0328
Test Year Ended December 31, 2007

Surrebuttal Schedule CSB-10

OPERATING MARGIN ADJUSTMENT NO. 1 - REVENUE AND EXPENSE ANNUALIZATIONS

LINE NO.	DESCRIPTION	[A] COMPANY AS FILED	[B] STAFF ADJUSTMENTS	[C] STAFF AS ADJUSTED
1	Total Margin Revenues	$ 30,530,904	$ -	$ 30,530,904
2	Cooperative's Annualization for Large Pwr Cust	-	(368,953)	(368,953)
3	Total Margin Revenues to be annualized	$ 30,530,904	$ (368,953)	$ 30,161,951
4	Factor to Annualize Revenues to End of Test Year	0.00%		0.9935%
5	**Revenue Annualization Adjustment**	$ -	**$ 303,312**	$ 303,312
6				
7	**Variable Expenses Not Recovered Through Fuel Adjustor**			
8	Transmission - Operation and Maintenance	$ 253,985	$ 2,523	$ 256,508
9	Distribution - Operations	$ 8,524,851	$ 84,691	$ 8,609,542
10	Distribution - Maintenance	$ 2,532,504	$ 25,159	$ 2,557,663
11	Customer Accounting	$ 3,024,637	$ 30,049	$ 3,054,686
12	Customer Service	$ 680,691	$ 6,762	$ 687,453
13		$ 15,016,668	**$ 149,184**	$ 15,165,852

LINE NO.	Calculation of Annualization Factor	
14		
15		
19	49,738	2007 Year-end Customer Count per Form 7
20	48,769	2006 Year-end Customer Count per Form 7
21	969	
22	1.99%	Growth Rate (969 / 48,769)
23		
24	0.9935%	Annualization Factor - 2007 Growth Rate divided by 2
25		
26		
27		
28		

Caculation of Variable Expenses Not Recovered Through Fuel Adjustor

LINE NO.	Description	Amount	2007 Growth Rate	Adjustment to Expenses
33	Transmission - Operation and Maintenance	$ 253,985	0.9935%	$ 2,523
34	Distribution - Operations	$ 8,524,851	0.9935%	$ 84,691
35	Distribution - Maintenance	$ 2,532,504	0.9935%	$ 25,159
36	Customer Accounting	$ 3,024,637	0.9935%	$ 30,049
37	Customer Service	$ 680,691	0.9935%	$ 6,762
38	Total Variable Expenses Not Recovered Through Fuel Adj	$ 15,016,668		$ 149,184

References:
Column A: Schedule CSB-9
Column B: Testimony, CSB
Column C: Column [A] + Column [B]

Sulphur Springs Valley Electric Cooperative
Docket No. E-01575A-08-0328
Test Year Ended December 31, 2007

Surrebuttal Schedule CSB-11

OPERATING MARGIN ADJUSTMENT NO. 2 - MISCELLANEOUS SERVICE CHARGE REVENUE

LINE NO.	DESCRIPTION	[A] COMPANY AS FILED	[B] STAFF ADJUSTMENTS	[C] STAFF AS ADJUSTED
1	Fort Huachuca	$ 2,822,220	$ -	$ 2,822,220
2	Electric Plant - Leased	$ 10,011	$ -	$ 10,011
3	Misc Service Charge Revenue	$ 738,402	$ (91,590)	$ 646,812
4	Rent from Electric Property	$ 819,651	$ -	$ 819,651
5	Other Electric Revenues	$ 783	$ -	$ 783
6	Total Other Revenues	$ 4,391,068	$ (91,590)	$ 4,299,478
7				
8				
9		Miscellaneous Service Charges		
10	Existing Member Connect Fee - Regular Hrs	$ 253,775	-	$ 253,775
11	Connect Fee - After Hours	$ 2,835	-	$ 2,835
12	Non-Pay Trip Fee - Regular Hours	$ 160,650	-	$ 160,650
13	Non-Pay Trip Fee - After Hours	$ 29,880	-	$ 29,880
14	Pump and Equipment Test	$ 480	-	$ 480
15	Radio Control Install Fee	$ 7,125	-	$ 7,125
16	Temporary Meter	$ 2,185	-	$ 2,185
17	Special After Hours Connect Fee	$ 620	-	$ 620
18	Aid to Construction - Line Extension	$ 91,590	(91,590)	$ -
19	Revenue from Lump Sum ISAC Payments	$ 34,117	-	$ 34,117
20	Late Charge	$ 124,033	-	$ 124,033
21	Penalty for Irrigation Override	$ 584	-	$ 584
22	Collection Service Charges Removed	$ (1,537)	-	$ (1,537)
23	Taxes Included in Service Charges in GL	$ 28,974	-	$ 28,974
24	Mileage Included in Service Charges in GL	$ 3,076	-	$ 3,076
25	NSF Check Reclassified	$ 15	-	$ 15
26	Total Misc Service Charge Revenue	$ 738,402	(91,590)	$ 646,812

References:

Column A: Cooperative provided workpaper
Column B: Testimony, CSB
Column C: Column [A] + Column [B]

Sulphur Springs Valley Electric Cooperative
Docket No. E-01575A-08-0328
Test Year Ended December 31, 2007

Surrebuttal Schedule CSB-12

OPERATING MARGIN ADJUSTMENT NO. 3 - 2008 FORT HUACHUCA MARGIN INCREASE

LINE NO.	DESCRIPTION	[A] COMPANY AS FILED	[B] STAFF ADJUSTMENTS	[C] STAFF AS ADJUSTED	
1	2008 Fort Huachuca Margin Increase	$ -	$ -	$ -	Removed $918,806
2					
3					
4					
5					
6					
7		[D]	[E]	[F]	
8		2007	Increase in	2008	
9		Fort Huachuca	Fort Huachuca	Fort Huachuca	
10		**CSB 3.4**	Margins	**CSB 3.5**	
11	Revenues	$ 2,824,391	$ 5,936,956	$ 8,761,346	
12	Expenses	$ 1,447,039	$ 5,018,150	$ 6,465,189	
13	Difference	$ 1,377,351	**$ 918,806**	$ 2,296,157	

References:

Column A: Cooperative Schedule A-1
Column B: Testimony, CSB; Data Request Response CSB 3.4 and CSB 3.5
Column C: Column [A] + Column [B]

Sulphur Springs Valley Electric Cooperative
Docket No. E-01575A-08-0328
Test Year Ended December 31, 2007

Surrebuttal Schedule CSB-13

OPERATING MARGIN ADJUSTMENT NO. 4 - BASE COST OF POWER AND WHOLESALE POWER COST ADJUSTOR

LINE NO.	DESCRIPTION	[A] COMPANY AS FILED	[B] STAFF ADJUSTMENTS	[C] STAFF AS ADJUSTED
1	*Revenues*			
2	Base Cost of Power Revenue ("BCOP")	$ 47,167,753	$ 10,523,834	$ 57,691,587
3	Rounding	(3)	3	-
4	Base Cost of Power Revenue Per Company	$ 47,167,750	$ 10,523,837	$ 57,691,587
5	Staff Recommended Increase To BCOP	-	-	-
6		$ 47,167,750	$ 10,523,837	$ 57,691,587
7	Wholesale Power Cost Adjustor ("WPCA")	10,523,837	(10,523,837)	-
8	Total Base Cost of Power and WPCA	57,691,587	-	57,691,587
9	*Expenses*			
10	Purchased Power	$ 57,691,587	$ 0	$ 57,691,587
11	**Operating Margin (Line 8 - Line 10)**	**$ -**	**$ (0)**	**$ (0)**
12				
13				
14				
15				
16				
17	Test Year Sales (In kWhs)	799,860,156	-	799,860,156
18	Multiplied by: Base Cost of Power per kWh	0.072127092	-	0.072127092
19	Total Base Cost of Power	$ 57,691,587	$ -	$ 57,691,587

References:

Column A: Cooperative Schedule A-1
Column B: Testimony, CSB
Column C: Column [A] + Column [B]

Sulphur Springs Valley Electric Cooperative
Docket No. E-01575A-08-0328
Test Year Ended December 31, 2007

Surrebuttal Schedule CSB-14

OPERATING MARGIN ADJUSTMENT NO. 5 - DSM EXPENSES

LINE NO.	Acct. No.	DESCRIPTION	[A] COMPANY AS FILED CSB 5-2	[B] STAFF ADJUSTMENTS	[C] STAFF AS ADJUSTED
1	909.00	Production costs for Co-op Connection	$ 228	$ (228)	$ -
2	909.10	Printing costs for Co-op Connection	$ 8,634	$ (8,634)	$ -
3	909.10	Costs for Currents Magazine	$ 5,174	$ (5,174)	$ -
4	912.20	Rebates to existing homeowners	$ 94,800	$ (94,800)	$ -
5	912.40	Inspections on Touchstone Energy homes	$ 6,857	$ (6,857)	$ -
6	912.40	Manpower costs	$ 24,544	$ (24,544)	$ -
7	912.40	Newspaper costs to Tyau Advertising	$ 5,143	$ (5,143)	$ -
8	912.40	Radio advertising to Tyau Advertising	$ 4,582	$ (4,582)	$ -
9	912.40	TV advertising to Tyau Advertising	$ 6,290	$ (6,290)	$ -
10	912.55	Newspaper costs to Tyau Advertising	$ 6,523	$ (6,523)	$ -
11	912.55	Radio advertising to Tyau Advertising	$ 3,839	$ (3,839)	$ -
12	912.55	TV advertising to Tyau Advertising	$ 2,056	$ (2,056)	$ -
13	913.00	TV advertising to Tyau Advertising	$ 2,871	$ (2,871)	$ -
14	921.00	Newspaper costs to Tyau Advertising	$ 3,643	$ (3,643)	$ -
15	921.00	Radio advertising to Tyau Advertising	$ 4,575	$ (4,575)	$ -
16	921.00	TV advertising to Tyau Advertising	$ 21,814	$ (21,814)	$ -
17		Variance with amounts reported to ACC	$ 2,823	$ (2,823)	$ -
18		2007 DSM Costs reported to the ACC	$ 204,396	$ (204,396)	$ -
19	912.50	All Electric Rebates	$ 280,600	$ (280,600)	$ -
20		TOTAL	$ 484,996	$ (484,996)	$ -

References:
Column A: Cooperative Data Request Response CSB 5-2
Column B: Testimony, CSB
Column C: Column [A] + Column [B]

Sulphur Springs Valley Electric Cooperative
Docket No. E-01575A-08-0328
Test Year Ended December 31, 2007

OPERATING MARGIN ADJUSTMENT NO. 6 - EMPLOYEE PAYROLL, BENEFITS, & PAYROLL TAXES

LINE NO.	DESCRIPTION	[A] COMPANY AS FILED	[B] STAFF ADJUSTMENTS	[C] STAFF AS ADJUSTED
1	Transmission Operation and Maintenance	$ 6,964	$ (3,570)	$ 3,394
2	Distribution - Operations	$ 431,251	$ (221,101)	$ 210,150
3	Distribution - Maintenance	$ 129,945	$ (66,622)	$ 63,322
4	Consumer Accounting	$ 150,970	$ (77,402)	$ 73,568
5	Customer Service	$ 36,825	$ (18,880)	$ 17,945
6	Sales	$ 6,880	$ (3,527)	$ 3,353
7	Administrative and General	$ 258,372	$ (132,467)	$ 125,906
8		**$ 1,021,207**	$ (523,570)	**$ 497,637**
9				

LINE NO.		Payroll	Employee Benefits	Payroll Tax	Total
10-11					
12	Transmission Oper & Maint	$ 3,003	$ 138	$ 253	$ 3,394
13	Distribution - Operations	$ 185,955	$ 8,541	$ 15,654	$ 210,150
14	Distribution - Maintenance	$ 56,032	$ 2,574	$ 4,717	$ 63,322
15	Consumer Accounting	$ 65,098	$ 2,990	$ 5,480	$ 73,568
16	Customer Service	$ 15,879	$ 729	$ 1,337	$ 17,945
17	Sales	$ 2,967	$ 136	$ 250	$ 3,353
18	Administrative and General	$ 111,410	$ 5,117	$ 9,378	$ 125,906
19		$ 440,343	$ 20,226	$ 37,068	**$ 497,637**
20					
21					

LINE NO.		Payroll	Employee Benefits	Payroll Tax	Total	Percent to Total
22-23						
24	Transmission Oper & Maint	$ 5,603	$ 882	$ 479	$ 6,964	0.68%
25	Distribution - Operations	$ 346,904	$ 54,856	$ 29,492	$ 431,251	42.23%
26	Distribution - Maintenance	$ 104,429	$ 16,369	$ 9,146	$ 129,945	12.72%
27	Consumer Accounting	$ 121,096	$ 19,395	$ 10,478	$ 150,970	14.78%
28	Customer Service	$ 29,528	$ 4,715	$ 2,583	$ 36,825	3.61%
29	Sales	$ 5,483	$ 910	$ 486	$ 6,880	0.67%
30	Administrative and General	$ 207,063	$ 33,442	$ 17,867	$ 258,372	25.30%
31		$ 820,106	$ 130,570	$ 70,531	**$ 1,021,207**	100.00%

References:

Column A: Cooperative Schedule A-3.0, Page 3 of 3;
Column B: Testimony, CSB; Data Request Response CSB 2.21
Column C: Column [A] + Column [B]

Calculation of Staff Adjusted Payroll Expense				
Line No.	Description	Company as Filed Sch A-7.0	Staff Adjustments	Staff as Adjusted
1	Actual test year payroll	$ 10,693,957	$ -	$ 10,693,957
2	Actual test year overtime	944,963	-	944,963
3		11,638,920	-	11,638,920
4				
5	Payroll for employees hired after test year	433,826	(433,826)	-
6	Adjustment to actual test year overtime	169,944	(169,944)	-
7	Reconciling item	18,134	(18,134)	-
8		621,904	(621,904)	-
9				
10	Adjusted total payroll	12,260,825	(621,904)	11,638,920
11	x Payroll expensed ratio	1	-	1
12	Adjusted Payroll Expenses	7,487,011	(379,763)	7,107,248
13	Less: Test year payroll expensed	6,666,905	-	6,666,905
14	**Test year adjusted payroll expense**	**820,106**	**(379,763)**	**440,343**

Calculation of Staff Adjusted Employee Benefits				
Line No.	Description	Company as Filed Sch A-8.0	Staff Adjustments	Staff as Adjusted
1	Medical and Prescription	$ 1,030,671	$ (64,378)	$ 966,293
2	Vision	$ 20,457	$ (1,160)	$ 19,297
3	Dental	$ 64,986	$ (4,028)	$ 60,958
4	Life Insurance	$ 47,150	$ (1,805)	$ 45,345
5	Long-Term Disability	$ 93,347	$ -	$ 93,347
6	401K Plan	$ 328,225	$ -	$ 328,225
7	Defined Benefit Pension Plan	$ 1,987,943	$ -	$ 1,987,943
8	Retiree Benefits	$ 47,500	$ (91,537)	$ (44,037)
9	Postretirement Benefits	$ 526,067	$ -	$ 526,067
10	Workers Compensation	$ 176,234	$ -	$ 176,234
11	Total	$ 4,322,581	$ (162,908)	$ 4,159,673
12	x Expensed Ratio	67.734%		67.734%
13	Adjusted Benefits Expensed	$ 2,927,838	$ (110,344)	$ 2,817,495
14	Less: Test Year Expense	$ 2,797,269	$ -	$ 2,797,269
15	**Adjustment**	**$ 130,570**	**$ (110,344)**	**$ 20,226**

Calculation of Staff Adjusted Payroll Taxes				
Line No.	Description	Company as Filed Sch A-13.0	Staff Adjustments	Staff as Adjusted
1	FICA	$ 907,617		$ 859,120
2	Federal Unemployment Taxes	$ 11,468		$ 10,908
3	State Unemployment Taxes	$ 7,454		$ 7,090
4	Total	$ 926,539		$ 877,118
5	x Payroll Expensed Ratio	$ 1		$ 1
6	Adjusted Payroll Taxes Expensed	$ 627,372		$ 593,909
7	Test Year Amount	$ 556,841		$ 556,841
8	Adjustment	$ 70,531		$ 37,068

Sulphur Springs Valley Electric Cooperative
Docket No. E-01575A-08-0328
Test Year Ended December 31, 2007

Surrebuttal Schedule CSB-16

OPERATING MARGIN ADJUSTMENT NO. 7 - GDS EXPENSES

		[A]	[B]	[C]
LINE NO.	**DESCRIPTION**	**COMPANY AS FILED CSB 3.13**	**STAFF ADJUSTMENTS**	**STAFF AS ADJUSTED**
1	Administrative and General Expenses	$ 4,014,255	$ -	$ 4,014,255
2	Admin and General Exp, GDS Associates	$ 212,217	$ (51,427)	$ 160,790
3	Total Administrative and General Expenses	$ 4,226,472	$ (51,427)	$ 4,175,045
4			-	-
5				

				[D]	[E]	[F]
6						
7						
8						
9	**Invoice No.**	**Invoice Date**	**DESCRIPTION**	**COMPANY AS FILED CSB 3.13**	**STAFF ADJUSTMENTS**	**STAFF AS ADJUSTED**
10	52193	9/18/2006	GDS Associates, Inc.	$ 14,706	$ (14,706)	$ -
11	52759	10/18/2006	GDS Associates, Inc.	$ 20,767	$ (20,767)	$ -
12	53381	11/21/2006	GDS Associates, Inc.	$ 23,738	$ (23,738)	$ -
13	54020	12/18/2006	GDS Associates, Inc.	$ 12,094	$ (12,094)	$ -
14				$ 71,305	$ (71,305)	$ -
15						
16	54463	1/19/2007	GDS Associates, Inc.	$ 12,878	$ -	$ 12,878
17	55226	2/26/2007	GDS Associates, Inc.	$ 11,645	$ -	$ 11,645
18	55652	3/19/2007	GDS Associates, Inc.	$ 14,497	$ -	$ 14,497
19	56194	4/19/2007	GDS Associates, Inc.	$ 12,068	$ -	$ 12,068
20	56748	5/11/2007	GDS Associates, Inc.	$ 8,961	$ -	$ 8,961
21	57238	6/12/2007	GDS Associates, Inc.	$ 10,854	$ -	$ 10,854
22	57775	7/19/2007	GDS Associates, Inc.	$ 19,422	$ -	$ 19,422
23	58526	8/17/2007	GDS Associates, Inc.	$ 8,306	$ -	$ 8,306
24	59146	9/14/2007	GDS Associates, Inc.	$ 8,318	$ -	$ 8,318
25	59876	10/18/2007	GDS Associates, Inc.	$ 9,127	$ -	$ 9,127
26	60690	11/29/2007	GDS Associates, Inc.	$ 21,842	$ -	$ 21,842
27	61020	12/12/2007	GDS Associates, Inc.	$ 7,120	$ -	$ 7,120
28	81707	8/17/2007	GDS Associates, Inc.	$ (4,126)	$ -	$ (4,126)
29				$ 140,912	$ -	$ 140,912
30						
31				$ 212,217	$ (71,305)	$ 140,912
32						
33	61146	12/18/2007	GDS Associates, Inc.	$ -	$ 18,644	$ 18,644
34	61200	12/21/2007	GDS Associates, Inc.	$ -	$ 1,235	$ 1,235
35				$ -	$ 19,879	$ 19,879
36						
37			Total	$ 212,217	$ (51,427)	$ 160,790

References:
Column A: Cooperative Schedule A-1
Column B: Testimony, CSB; Data Request Response CSB 1.39, CSB 2.24, CSB 3.10, CSB 3.13
Column C: Column [A] + Column [B]

Sulphur Springs Valley Electric Cooperative
Docket No. E-01575A-08-0328
Test Year Ended December 31, 2007

Surrebuttal Schedule CSB-17

OPERATING MARGIN ADJUSTMENT NO. 8 - NORMALIZED LEGAL EXPENSES

LINE NO.	DESCRIPTION	[A] COMPANY AS FILED CSB 5-2	[B] STAFF ADJUSTMENTS	[C] STAFF AS ADJUSTED
1	Administrative and General Expenses	$ 4,130,635	-	$ 4,130,635
2	Admin and General Exp, Legal Expenses	$ 95,837	(52,892)	$ 42,945
3	Total Administrative and General Expenses	$ 4,226,472	(52,892)	$ 4,173,580
			-	-

LINE NO.	DESCRIPTION		[A] COMPANY AS FILED CSB 5-2	[B] STAFF ADJUSTMENTS	[C] STAFF AS ADJUSTED
1	Babacomari Ranch Company Litigation		$ 9,500	$ (6,333)	$ 3,167
2	2007 $70 Million Financing		$ 23,738	$ (15,826)	$ 7,913
3	CREBS ACC Financing Filing		$ 9,893	$ (6,595)	$ 3,298
4	2007-2008 Rest Plan & Tariff		$ 20,612	$ (13,741)	$ 6,871
5	Labor Matters		$ 32,094	$ (10,397)	$ 21,697
6			$ 95,837	$ (52,892)	$ 42,945
7					
8					
9	Babacomari Ranch Company Litigation	CSB 2.10	$ 9,500	normalized over 3 years	$ 3,167
10	2007 $70 Million Financing	CSB 2.14	$ 23,738	normalized over 3 years	$ 7,913
11	CREBS ACC Financing Filing	CSB 2.15	$ 9,893	normalized over 3 years	$ 3,298
12	2007-2008 Rest Plan & Tariff	CSB 2.16	$ 20,612	normalized over 3 years	$ 6,871
13			$ 63,743		$ 21,248
14					
15				2006 Labor Matters	$ 22,996
16				2007 Labor Matters	$ 32,094
17				2008 Labor Matters	$ 10,002
18					$ 65,092
19				normalized over 3 years	$ 3
20					$ 21,697

References:
Column A: Cooperative Schedule A-1
Column B: Testimony, CSB; Data Request Response CSB 1.37, CSB 2.10 to CSB 2.16
Column C: Column [A] + Column [B]

Sulphur Springs Valley Electric Cooperative
Docket No. E-01575A-08-0328
Test Year Ended December 31, 2007

Surrebuttal Schedule CSB-18

OPERATING MARGIN ADJUSTMENT NO. 9 - CHARITABLE CONTRIBUTIONS & OTHER EXPENSES

LINE NO.	DATA REQUEST RESPONSE	DESCRIPTION	[A] COMPANY AS FILED	[B] STAFF ADJUSTMENTS	[C] STAFF AS ADJUSTED
1	CSB 1-34	Dues to Grand Canyon Electric Coop Assoc.	$ 130,697	$ (16,246)	$ 114,451
2	CSB 1-41	Dues for social and service clubs	$ 5,102	$ (5,102)	$ -
3	CSB 1-41	Memberships to Industry Associations	$ 44,880	$ (21,366)	$ 23,515
4	CSB 1-41	Charitable contributions	$ 51,876	$ (51,876)	$ -
5	CSB 1-41	Sponsorships	$ 93,461	$ (93,461)	$ -
6	CSB 1-41	Gifts, flowers, and awards	$ 42,260	$ (42,260)	$ -
7	CSB 1-41	Food and beverages	$ 29,442	$ (7,826)	$ 21,616
8	CSB 1-41	Luncheons and dinners	$ 39,147	$ (39,147)	$ -
9	CSB 1-41	Employee parties, picnics, or similar events	$ 35,120	$ (35,120)	$ -
10	CSB 1-41	Entertainment	$ 2,464	$ (2,464)	$ -
11	CSB 2-25	Advertising	$ 260,059	$ (159,921)	$ 100,138
11		TOTAL	$ 343,752	**$ (298,622)**	$ 45,130

References:

Column A: Cooperative Data Request Response CSB 1-34, 1-41, 2-25
Column B: Testimony, CSB
Column C: Column [A] + Column [B]

Sulphur Springs Valley Electric Cooperative
Docket No. E-01575A-08-0328
Test Year Ended December 31, 2007

Surrebuttal Schedule CSB-19

OPERATING MARGIN ADJUSTMENT NO. 10 - INCENTIVE PAY

LINE NO.	DESCRIPTION	[A] COMPANY AS FILED	[B] STAFF ADJUSTMENTS	[C] STAFF AS ADJUSTED
1	Transmission Operation and Maint	$ 307	$ (307)	$ -
2	Distribution - Operations	$ 19,028	$ (19,028)	$ -
3	Distribution - Maintenance	$ 5,733	$ (5,733)	$ -
4	Consumer Accounting	$ 6,661	$ (6,661)	$ -
5	Customer Service	$ 1,625	$ (1,625)	$ -
6	Sales	$ 304	$ (304)	$ -
7	Administrative and General	$ 11,400	$ (11,400)	$ -
8		$ 45,058	$ (45,058)	$ -
9				
10				

LINE NO.	DESCRIPTION	[D] Payroll	[E] Employee Benefits	[G] Payroll Tax	[H] Total	[I] Percent to Total	[J] Incentive Pay $ 45,058
15	Trans Oper & Maint	$ 5,603	$ 882	$ 479	$ 6,964	0.68%	**$ 307**
16	Distr - Operations	$ 346,904	$ 54,856	$ 29,492	$ 431,251	42.23%	**$ 19,028**
17	Distr - Maintenance	$ 104,429	$ 16,369	$ 9,146	$ 129,945	12.72%	**$ 5,733**
18	Consumer Accounting	$ 121,096	$ 19,395	$ 10,478	$ 150,970	14.78%	**$ 6,661**
19	Customer Service	$ 29,528	$ 4,715	$ 2,583	$ 36,825	3.61%	**$ 1,625**
20	Sales	$ 5,483	$ 910	$ 486	$ 6,880	0.67%	**$ 304**
21	Admin and Gen	$ 207,063	$ 33,442	$ 17,867	$ 258,372	25.30%	**$ 11,400**
22		$ 820,106	$ 130,570	$ 70,531	$ 1,021,207	100.00%	**$ 45,058**

References:

Column A: Schedule CSB-19, Column J
Column B: Testimony, CSB
Column C: Column [A] + Column [B]

Sulphur Springs Valley Electric Cooperative
Docket No. E-01575A-08-0328
Test Year Ended December 31, 2007

Surrebuttal Schedule CSB-20

OPERATING INCOME ADJUSTMENT NO. 11 - INTEREST EXP ON LONG-TERM DEBT

		[A]	[B]	[C]
LINE NO.	**DESCRIPTION**	**COMPANY AS FILED**	**STAFF ADJUSTMENTS**	**STAFF AS ADJUSTED**
1	Interest Expense on Long-term Debt	$ 6,994,249	$ (426,301)	$ 6,567,948
2				
3				

Line		Principal Per Company	Difference	Principal Per Staff	Interest Rate	Interest
6	CFC Notes	$ 7,580,857	$ -	$ 7,580,857	6.99%	$ 529,902
7	CFC Notes	$ 223,130	$ -	$ 223,130	5.69%	$ 12,696
8	CFC Notes	$ 6,679,114	$ -	$ 6,679,114	6.19%	$ 413,437
9	CFC Notes	$ 1,094,315	$ -	$ 1,094,315	5.44%	$ 59,531
10	CFC Notes	$ 4,505,110	$ -	$ 4,505,110	4.90%	$ 220,750
11	CFC Notes	$ 3,736,739	$ -	$ 3,736,739	4.60%	$ 171,890
12	CFC Notes	$ 4,704,874	$ -	$ 4,704,874	4.65%	$ 218,777
13	CFC Notes	$ 6,940,043	$ -	$ 6,940,043	5.30%	$ 367,822
14	CFC Notes	$ 8,883,720	$ -	$ 8,883,720	6.39%	$ 567,670
15	CFC Notes	$ 248,343	$ -	$ 248,343	3.84%	$ 9,536
16	CFC Notes	$ 484,009	$ -	$ 484,009	4.14%	$ 20,038
17	CFC Notes	$ 636,296	$ -	$ 636,296	4.39%	$ 27,933
18	CFC Notes	$ 784,238	$ -	$ 784,238	4.64%	$ 36,389
19	CFC Notes	$ 890,391	$ -	$ 890,391	4.84%	$ 43,095
20	CFC Notes	$ 962,025	$ -	$ 962,025	5.04%	$ 48,486
21	CFC Notes	$ 1,061,492	$ -	$ 1,061,492	5.09%	$ 54,030
22	CFC Notes	$ 2,059,876	$ -	$ 2,059,876	5.19%	$ 106,908
23	CFC Notes	$ 6,811,488	$ -	$ 6,811,488	5.24%	$ 356,922
24	CFC Notes	$ 6,511,760	$ -	$ 6,511,760	5.29%	$ 344,472
25	CFC Notes	$ 5,779,352	$ -	$ 5,779,352	5.59%	$ 323,066
26	CFC Notes	$ 5,881,037	$ -	$ 5,881,037	6.34%	$ 372,858
27	CFC Notes	$ 8,410,398	$ -	$ 8,410,398	6.59%	$ 554,245
28	CFC Notes	$ 2,976,264	$ -	$ 2,976,264	6.54%	$ 194,648
29	CFC Notes	$ 9,915,144	$ -	$ 9,915,144	6.09%	$ 603,832
30	CFC Notes	$ 2,000,000	$ -	$ 2,000,000	4.90%	$ 98,000
31	CFC Notes	$ 67,666	$ -	$ 67,666	4.90%	$ 3,316
32	CFC Notes	$ 8,000,000	$ -	$ 8,000,000	4.40%	$ 352,000
33	CFC Notes	$ 18,000,000	$ (8,700,000)	$ 9,300,000	4.90%	$ 455,700
34		$ 125,827,680	$ (8,700,000)	$ 117,127,680		$ 6,567,948

References:
Column A: Cooperative Schedule A-1.0, A-14.0
Column B: Testimony, CSB; Data Request Response STF 8.22
Column C: Column [A] + Column [B]

Sulphur Springs Valley Electric Cooperative
Docket No. E-01575A-08-0328
Test Year Ended December 31, 2007

Surrebuttal Schedule CSB-21

OPERATING MARGIN ADJUSTMENT NO. 12 - CAPITAL CREDITS

LINE NO.	DESCRIPTION	[A] COMPANY AS FILED	[B] STAFF ADJUSTMENTS	[C] STAFF AS ADJUSTED
1	G&T Capital Credits	$ 2,592,402	$ (2,592,402)	$ -
2	Other Capital Credits	518,101	(130,414)	387,687
3		$ 3,110,503	$ (2,722,816)	$ 387,687
4				
5				
6				Cash
7				Capital Credits
8				CSB 3.16
9	G&T Capital Credits - AEPCO			$ -
10	Other Capital Credits - CFC			375,754
11	Other Capital Credits - NISC			60
12	Other Capital Credits - NRTC			3,823
13	Other Capital Credits - Federated Rural Insurance			6,041
14	Other Capital Credits - CRC			2,009
15				$ 387,687

References:

Column A: Cooperative Schedule A-1
Column B: Testimony, CSB; CSB 3.15, CSB 3.16
Column C: Column [A] + Column [B]

Sulphur Springs Valley Electric Cooperative
Docket No. E-01575A-08-0328
Test Year Ended December 31, 2007

Surrebuttal Schedule CSB-22

CASH FLOW ANALYSIS
As of 12/31/2007

Line No.			
1	Staff Adjusted Recommended Revenue	$	100,420,597
2	Staff Recommended Purchased Power	$	(57,691,587)
3	**Operating Revenue Excluding Pur Pwr:**	$	**42,729,010**
4			
5			
6	Purchased Power	$	57,691,587
7	Transmission Operation and Maintenance	$	252,631
8	Distribution - Operations	$	8,369,413
9	Distribution - Maintenance	$	2,485,308
10	Consumer Accounting	$	2,970,623
11	Customer Service	$	666,948
12	Sales	$	558,495
13	Administrative and General	$	3,194,669
14	Depreciation and Amortization	$	7,574,650
15	Payroll and Property Taxes	$	1,290,758
16	**Total Staff Adj Operating Expenses**	$	**85,055,081**
17	Less: Purchased Power	$	**(57,691,587)**
18	**Total Staff Adj Operating Expenses Excluding Pur Power**	$	**27,363,494**
19			
20	**Total Operating Margin Excl Pur Pwr**	$	**15,365,516**
21	Add back Depreciation Expense		$7,574,650
22	**Total Cash Available to Pay Principal and Interest on L.T. Debt**	$	**22,940,166**
23	**Total Debt Service for Total Annual Loans (from line 42)**	$	**(14,122,976)**
24	**Net Margin Excl Pur Pwr**	$	**8,817,190**
25			
26			
27			
28			
29	***Existing Debt Service on $97.76 Million Loan Balances:***		
30	Annual Principal Payment Per Form 7 and Coop Sch A-14		$4,269,396
31	Annual Interest Payment Per Form 7 and Coop Sch A-14		$5,620,981
32	**TotalDebt Service for Existing Loan**		**$9,890,377**
33			
34	***2007 Commission Approved $70 Million Loan***		
35	Annual Principal Payment		$781,781
36	Annual Interest Payment		$3,450,818
37	**Total Debt Service on 2007 Commission Approved $70 Million Loan**		**$4,232,599**
38			
39	**Total Debt Service for Existing and $97.76 Million and 2007 $70 Million**		
40	Total Annual Principal Payments		$5,051,177
41	Total Annual Interest Payment		$9,071,799
42	**Total Debt Service for Existing and $97.76 Million and 2007 $70 Million (L32+L37)**		**$14,122,976**

Sulphur Springs Valley Electric Cooperative
Docket No. E-01575A-08-0328
Test Year Ended December 31, 2007

Surrebuttal Schedule CSB-23

Increase In Equity

From Cooperative Rebuttal Exhibit DH-9:

	2008	2009	2010	2011	2012	2013	2014	2015	2016
Long-Term Debt	$ 125,311,087	$ 150,207,811	$ 169,368,385	$ 188,528,959	$ 207,689,533	$ 226,850,107	$ 246,010,681	$ 265,171,255	$ 284,331,829
Equity	$ 42,836,486	$ 45,704,561	$ 54,308,786	$ 62,913,011	$ 71,517,236	$ 80,121,461	$ 88,725,686	$ 97,329,911	$ 105,934,136
Total Capitalization	$ 168,147,573	$ 195,912,372	$ 223,677,171	$ 251,441,970	$ 279,206,769	$ 306,971,568	$ 334,736,367	$ 362,501,166	$ 390,265,965
L.T-Debt Increases Per Coop	$ 27,521,073	$ 24,896,724	$ 19,160,574	$ 19,160,574	$ 19,160,574	$ 19,160,574	$ 19,160,574	$ 19,160,574	$ 19,160,574
Equity Increases Per Coop		$ 2,868,075	$ 8,604,225	$ 8,604,225	$ 8,604,225	$ 8,604,225	$ 8,604,225	$ 8,604,225	$ 8,604,225

	Per Staff			
	Equity	Long-term Debt	Total	Pecentage
Year-end 2008	$ 42,836,486	$ 125,311,087		
Increases Per Coop	$ 2,868,075	$ 24,896,724		
Year-end 2009	$ 45,704,561	$ 150,207,811	$ 195,912,372	23.33%
Increases Per Coop	$ 8,604,225	$ 19,160,574		
Increases/(Decreases) Per Staff	$ 322,715	$ (918,806)		
Year-end 2010	$ 54,631,501	$ 168,449,579	$ 223,081,080	24.49%
Increases Per Coop	$ 8,604,225	$ 19,160,574		
Increases/(Decreases) Per Staff	$ 322,715	$ (918,806)		
Increases/(Decreases) Per Staff	$ -	$ (2,081,194)		
Year-end 2011	$ 63,558,441	$ 184,610,153	$ 248,168,594	25.61%
Increases Per Coop	$ 8,604,225	$ 19,160,574		
Increases/(Decreases) Per Staff	$ 322,715	$ (918,806)		
Increases/(Decreases) Per Staff	$ -	$ (2,081,194)		
Year-end 2012	$ 72,485,381	$ 200,770,727	$ 273,256,108	26.53%
Increases Per Coop	$ 8,604,225	$ 19,160,574		
Increases/(Decreases) Per Staff	$ 322,715	$ (918,806)		
Increases/(Decreases) Per Staff		$ (2,081,194)		
Increases/(Decreases) Per Staff	$ -	$ (1,916,057)		
Year-end 2013	$ 81,412,321	$ 215,015,244	$ 296,427,565	27.46%
Increases Per Coop	$ 8,604,225	$ 19,160,574		
Increases/(Decreases) Per Staff	$ 322,715	$ (918,806)		
Increases/(Decreases) Per Staff		$ (2,081,194)		
Increases/(Decreases) Per Staff	$ -	$ (1,916,057)		
Year-end 2014	$ 90,339,261	$ 229,259,760	$ 319,599,021	28.27%
Increases Per Coop	$ 8,604,225	$ 19,160,574		
Increases/(Decreases) Per Staff	$ 322,715	$ (918,806)		
Increases/(Decreases) Per Staff		$ (2,081,194)		
Increases/(Decreases) Per Staff	$ -	$ (1,916,057)		
Year-end 2015	$ 99,266,201	$ 243,504,277	$ 342,770,478	28.96%
Increases Per Coop	$ 8,604,225	$ 19,160,574		
Increases/(Decreases) Per Staff	$ 322,715	$ (918,806)		
Increases/(Decreases) Per Staff		$ (2,081,194)		
Increases/(Decreases) Per Staff	$ -	$ (1,916,057)		
Year-end 2016	$ 108,193,141	$ 257,748,793	$ 365,941,934	29.57%

EXHIBIT
S-8
admitted

BEFORE THE ARIZONA CORPORATION COMMISSION

KRISTIN K. MAYES
Chairman
GARY PIERCE
Commissioner
PAUL NEWMAN
Commissioner
SANDRA D. KENNEDY
Commissioner
BOB STUMP
Commissioner

IN THE MATTER OF THE APPLICATION OF SULPHUR SPRINGS ELECTRIC COOPERATIVE, INC. FOR A HEARING TO DETERMINE THE FAIR VALUE OF ITS PROPERTY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RETURN THEREON, TO APPROVE RATES DESIGNED TO DEVELOP SUCH RETURN AND FOR RELATED APPROVALS	)	DOCKET NO. E-01575A-08-0328

DIRECT

TESTIMONY

OF

WILLIAM MUSGROVE

ON BEHALF OF STAFF

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

FEBRUARY 17, 2009

TABLE OF CONTENTS

SCHEDULES

EXECUTIVE SUMMARY
SULPHUR SPRINGS VALLEY ELECTRIC COOPERATIVE, INC.
DOCKET NO. E-01575A-08-0328

Staff's testimony addresses Revenue Allocation and Rate Design, Tariff Changes, Service-Related Charges, Unbundled Tariffs and the need for a bill estimation tariff for Sulphur Springs Valley Electric Cooperative's ("SSVEC", "Sulphur Springs" or "Cooperative"). Staff's recommendations are summarized below:

1. Revenue Allocation and Rate Design
   Staff concludes and recommends that Sulphur Springs should be granted a revenue increase in the amount of $16,532,128 or 21.28 percent over present revenues in the amount of $77,699,100. Excluding other revenues, SSVEC originally requested an increase in the amount of $9,976,818 (increase of 11.31 percent), and were granted an increase in the amount of $6,008,830 for an increase of 6.81 percent as shown in WHM-1 at the bottom of page 4. A rate class summary of these data is depicted on page 6 of Staff's testimony.

2. Tariff Changes
   The tariff changes proposed by Sulphur Springs are generally acceptable to Staff. For example Staff supports the elimination of the existing Residential declining block rate. Another change viewed by Staff as being an improvement is the proposed Wholesale Power Cost Adjustment schedule. It has been centralized rather than printing its terms and conditions on each tariff schedule. Changes of this nature improve the readability of individual tariff sheets and allow for more efficient tariff maintenance. Sulphur Springs also proposes increasing the number of on-peak time-of-use hours to include Sundays. This change would create on-peak billing periods each day of the week, Monday through Sunday, and each week of the year. Staff initiated a request for data that supports such a change. Although SSVEC's response was fortified with empirical data indicating that coincident peaks may occur on any day of the week, Staff recommends retaining the existing time-of-use time periods.

3. Service Charge Fees
   Staff recommends increasing service fee revenues $344,965.

4. Unbundled Tariffs
   Sulphur Springs' unbundled rates are adequate because at this time they are not providing unbundled service to any customers. However if SSVEC were required to provide service under an open access arrangement, it would be necessary to provide more discrete information in their rate schedules.

5. Bill Estimation Tariff

Within thirty days of a decision in this matter, Staff recommends that Sulphur Springs be required to submit, through Docket Control for Commission approval, a separate tariff describing its bill estimation methodology.

INTRODUCTION

Q. Please state your name and business address.

A. My name is William Musgrove. My business address is 1200 West Washington Street, Phoenix, Arizona 85007.

Q. What is the nature of your work relationship with the Arizona Corporation Commission?

A. I am an Independent Contractor providing utilities consulting services to the Arizona Corporation Commission ("Commission") Utilities Division Staff ("Staff").

Q. Please state your educational background and business experience.

A. I received a Master of Business Administration Degree with a tested concentration in Finance and an elected concentration in Economics from Loyola College located in Baltimore, Maryland. I also received a Bachelor of Science Degree with a concentration in Business Administration from Johns Hopkins University located in Baltimore, Maryland, and later augmented the Undergraduate Degree with college-level mathematics credits that were also received from Johns Hopkins University. I am a tested Certified Energy Manager as certified by the Association of Energy Engineers. My business experiences entail 40-plus years in various positions with the Baltimore Gas and Electric Company ("BGE"). The positions relevant to the testimony I am sponsoring in this Proceeding involve more than 10 years experience in the Economic Research Department at BGE. During that period, I became fully proficient in understanding gas and electric utility financial records and the rate making process. I am thoroughly familiar with all phases and components of gas or electric rate cases, including rate design and Cost of Service protocols.

Q. Have you previously testified before any regulatory commission?

A. Yes. I appeared before the Arizona Corporation Commission ("ACC") in 2005, during a Southwest Gas Corporation rate proceeding (Docket No. G-01551A-04-0876), and in 2008, during a Graham County Electric Cooperative rate proceeding (Docket No. E-01749A-07-0236). I have also appeared before the ACC during several tariff-related proceedings.

Q. What is the scope of your testimony in this case?

A. My testimony will present Staff's position and recommendations regarding Sulphur Springs Valley Electric Cooperative's ("SSVEC", "Sulphur Springs" or "Cooperative") application for a general rate increase. Staff's testimony specifically addresses the topics of revenue allocation and rate design, proposed tariff changes, service-related charges, unbundled tariffs and a miscellaneous tariff matter regarding bill estimation procedures. Staff witnesses Crystal Brown, Julie McNeely-Kirwan, Steve Irvine and Prem Bahl have also provided testimonies regarding other aspects of Sulphur Springs' rate application.

REVENUE ALLOCATION AND RATE DESIGN

Q. Please describe Staff's revenue allocations.

A. Sulphur Springs' revised cost of service study illustrates that, to varying degrees, the Residential, General Service, and Lighting rate classes are barely paying or are paying less than their cost of service. Overall system return is reported to be approximately 4.57 percent. After incorporating Staff's adjustments, Residential, General Service, and Lighting rates of return improved slightly, but General Service Time-of-Use ("TOU") and Lighting continue to carry negative rates of return of 1.71 percent and approximately 6.33 percent, respectively. After applying Staff's recommended annual operating revenue in the amount of $100,097,882, Lighting rate of return is still negative at approximately 4.6

percent. Later in its testimony, Staff discusses its rate design recommendations regarding individual rate classes. After incorporating Staff's adjustments, overall system rate of return increased to approximately 6.54 percent. As derived and summarized in Schedule WHM-1, Staff is recommending increasing the non-Time-of-Use Residential class' monthly customer charge and energy rates by 10 percent and approximately 20 percent, respectively. Staff is recommending that the non-TOU General Service classes' monthly customer charges increase 17.39 percent and 16.09 percent for the non-demand and demand customers, respectively; and, respective energy revenues increase approximately 30 percent and 29 percent.

There are five Irrigation rate schedules with varying rate structures to accommodate nearly customized usage requirements: (1) Seasonal, (2) Load Factor, (3) Daily, (4) Weekly and (5) Daily/Large. Existing monthly customer charges for the five rate classes have been left unchanged by Sulphur Springs. Staff believes that existing monthly customer charges, which are fixed in the \$25-\$30 range, are appropriate for Irrigation customers, and recommends keeping them at current levels. It should be noted that proposed rates and resultant revenues are derived in WHM-1 whereas Schedule WHM-2 summarizes existing and proposed customer charges, energy rates (kWh) and demand (kW) rates that were developed in WHM-1. As indicated in WHM-1, Staff's recommended rates are designed to increase revenues for the irrigation classes as follows: (1) 20.41 percent, (2) 28.61 percent, (3) 17.20 percent, (4) 19.79 percent and (5) 21.78 percent.

There are approximately 343 non-TOU large user (demands equal to or greater than 50 KVA) commercial/industrial customers. Rate schedule "Large Power" serves the overwhelming majority (nearly 95 percent) of these customers, with the remaining 19 customers being served under SSVEC's "Seasonal" and "Industrial" large power schedules. The monthly customer charge for the Large Power rate payers is recommended by Staff to increase approximately 5.4 percent (WHM-2), and as indicated in WHM-1, Staff's recommended rates are designed to increase revenues by 18.66 percent. The monthly customer charge for the Large Power Seasonal rate payers is recommended by Staff to increase 12.50 percent and as indicated in WHM-1, Staff's recommended rates are designed to increase revenues by 21.21 percent. The monthly customer charge for the Large Power Industrial rate payers is recommended by Staff to increase 3.8 percent (WHM-2), and as indicated in WHM-1, Staff's recommended rates are designed to increase revenues by 21.60 percent.

Sulphur Springs has two Large Power Contract customers identified as Contract 1 and Contract 2. Contract 1 contains TOU rates which will be discussed in more detail in Staff's discussion of rate design. Existing monthly customer charges for both contract customers have been left unchanged by Sulphur Springs. Staff believes that the existing monthly customer charges are appropriate because each contract has been reviewed and accepted by the Commission as is required for large power contracts of this nature under its jurisdiction. Staff recommends 22.12 percent and 18.90 percent revenue increases for large power contract customer Nos. 1 and 2, respectively. The derivation of these increases is shown in WHM-1.

The monthly customer charge for the Recreation Vehicle ("RV") Parks is recommended by Staff to increase 3.7 percent, and as indicated in WHM-1, Staff's recommended rates are designed to increase revenues by 23.41 percent. It should be noted that RV rates proposed by Staff in the amounts of $43.55 (Customer Charge), $6.70 per kW (Demand) and $0.0766 per kWh (Energy) are not billed directly to the individual RV occupants. Rather, these rates are billed directly to the operators of the twelve RV parks.

Regarding the Street and Security Lighting rate classes ("Lighting classes"), SSVEC's revised cost of service study illustrates that the Lighting classes are currently providing a combined negative return of approximately 6.84 percent. Incorporating Staff's adjustments slightly improves the Lighting classes' rates of return to a combined negative return of approximately 6.33 percent. Excluding large customer contract classes, the lighting classes' combined rate of return is the lowest compared to other rate classes' returns. Consequently, Staff recommends accepting Sulphur Springs' proposed rates for its Street and Security lighting customers thereby increasing their revenues 17.04 percent and 9.13 percent, respectively (WHM-1).

Q. Has Staff developed revised recommended TOU rates for existing TOU customers?

A. Yes. The reason this class of customers is not included in the above discussions is that Sulphur Springs has a somewhat unique Commission approved approach regarding rate design for TOU customers. Staff first became aware of this uniqueness when reviewing direct testimony filed by Sulphur Springs. For example, the residential rate class only contains seventeen TOU customers in the Test Year compared to over 40,000 non-TOU residential customers. Staff initiated data requests inquiring why cost of service rate of return and relative rate of return data are not shown for residential TOU customers. The responses indicate that the Residential TOU class represents such a small portion of the combined TOU and non-TOU class that they are statistically insignificant. Staff accepts SSVEC's explanation and recommends rates that will increase: (1) Residential TOU revenues by 20.91 percent; (2) General Service TOU revenues by 27.38 percent; (3) Large Power TOU revenues by 20.95 percent; and, (4) Large Power Contract 1 TOU rates by 22.12 percent. SSVEC provided empirical data supporting proposed on-peak hour changes in that they indicate system-wide coincident peaks have been occurring on weekends. However, SSVEC estimates that Residential on-peak kWh usage will increase approximately 79 percent due to revised summer and winter on-peak periods. Staff has concluded that the migration from non-TOU to TOU would be encumbered by adding Sundays to TOU on-peak time periods.

Q. Has Staff developed a table that summarizes the revenue impact of its recommended rates upon each rate class?

A. The following table summarizes revenue increases as recommended by Staff for all customer classes:

Summary of Revenues from Customer Charges and Sales*

Rate Class	Present $	Proposed $	$ Increase	% Increase
Residential	$38,011,842	$45,765,857	$7,754,015	20.40%
General Service	$11,752,900	$14,882,975	$3,130,075	26.63%
General Service TOU	$82,889	$102,141	$19,252	23.23%
Irrigation	$10,885,135	$13,200,452	$2,315,317	21.27%
Large Power	$12,808,981	$15,258,662	$2,449,681	19.12%
Large Power TOU	$553,699	$669,713	$116,014	20.95%
Contracts-Excludes Ft. Huachuca	$2,444,636	$2,951,878	$507,242	20.75%
RV Parks	$393,347	$464,517	$71,170	18.09%
Street Lighting	$436,444	$548,690	$112,246	25.72%
Security Lighting	$264,653	$313,303	$48,650	18.38%
Un-metered & Preconst. $	$64,574	$73,040	$8,466	13.11
Totals	$77,699,100	$94,231,228	$16,532,128	21.28%

***Excludes WPCA and fee revenues; includes Base Cost of Power revenues**

Q. Will Staff briefly describe its rate design?

A. A summary of Staff's proposed rate design and resultant revenues is provided in WHM-1. The data above are derived from data contained in WHM-1. Staff's increase in the amount of $16,532,128 (plus a de minimis rounding under-collection in the amount of $541) matches revenue increases recommended by Crystal Brown on Schedule CSB-8 (Column B, Line 5 plus Column D, Line 10) filed with Ms. Brown's direct testimony. The allocation of incremental revenues to the various customer classes is based upon many factors as is discussed later in Staff's testimony. However, Sulphur Springs' rate design filed in this docket identified rate allocation proportions that guided Staff in allocating Staff's recommended revenue increases. In fact, the following four rate classes were allocated rates that are expected to produce incremental revenues equal to the revenues proposed by Sulphur Springs: Street Lights, Security Lights, Un-Metered service and Pre-Meter Construction service.

Q. Did Staff base its revenue allocations and rate design solely on Staff's cost of service study?

A. No. Staff's recommended rates reflect the combined consideration of setting rates that more accurately reflect classes cost of service, gradualism in change and Staff's recommended revenue requirement for Sulphur Springs.

Q. Will Staff be addressing the matters of cost of service and revenue requirement?

A. Yes. Staff witnesses Prem Bahl and Crystal Brown will be addressing cost of service and revenue requirement matters, respectively.

Q. Please further describe Staff's recommended rate design and its effect on Sulphur Springs' various customer classes.

A. Schedule WHM-2 contains all rates recommended by Sulphur Springs and Staff and identifies the respective percent changes. A typical bill analysis reflecting the effect of Sulphur Springs and Staff recommended rate changes on customers with various kWh usage levels is provided on schedule WHM-3 ("WHM-3"). Referencing data summarized in WHM-2, Staff recommends increasing the Residential monthly Customer Charge from $7.50 to $8.25. Staff is recommending that the proposed commodity rate be set at $0.11818 per kWh compared to the Cooperative's proposed rate of $0.11830 per kWh.

Based on an average residential customer's usage of 728 kWh per month, Staff's recommended rates will increase an average residential customer's bill by $15.97 or 20.40 percent (WHM-3).

For the Small Commercial rate class, Staff recommends increasing the monthly Customer Charge from $11.50 to $13.50. Staff is recommending that the proposed commodity rate be set at $0.11449 per kWh compared to the Cooperative's proposed rate of $0.11830 per kWh. Based on an average customer usage of 483 kWh per month, Staff's recommended rates will raise an average customer's bill by $14.89 or 27.62 percent.

For the Large Commercial rate class, Staff recommends increasing the monthly Customer Charge from $11.50 to $13.35. Staff is recommending that the proposed commodity rate be set at $0.11316 per kWh compared to the Cooperative's proposed rate of $0.11830 per kWh. Based on an average customer usage of 2,854 kWh per month, Staff's recommended rates will raise an average customer's bill by $78.67 or 26.90 percent.

For the Large Power rate class, Staff recommends increasing the monthly Customer Charge from $42.00 to $44.25. Staff is recommending that the proposed commodity rate be set at $0.07716 per kWh compared to the Cooperative's proposed rate of $0.06760 per kWh. Based on an average customer usage of 31,884 kWh per month, Staff's recommended rates will raise an average customer's bill by $517.00 or 18.66 percent.

The typical Security Lighting installation is a 100 watt, high pressure sodium light using 60 kWhs per month. Staff recommends increasing the present $9.10 monthly rate per fixture to $10.92 per month as proposed by Sulphur Springs. Staff supports this increase of 20 percent due to the negative rate of return for this class of service. The typical monthly bill is expected to increase $1.82 per fixture.

The typical Street Lighting installation is a 150 watt, high pressure sodium light using 54 kWhs per month. Staff recommends increasing the present $10.50 monthly rate per fixture to $13.13 per month as proposed by Sulphur Springs. Staff supports the increase of approximately 25 percent due to the negative rate of return for this class of service. The typical monthly bill is expected to increase $2.63 per fixture.

Q. **Why does Staff exclude Wholesale Power Costs from its rates?**

A. The base cost of power in this docket is $0.072127 per kWh. Staff's rates include this rate. The Wholesale Power Cost Adjustor ("WPCA") dollars are removed from Staff's rates to better reflect more accurate percentage increases to rates.

Q. **Does Staff have any other reasons for taking this approach when designing rates?**

A. Both approaches are valid (including or excluding WPCA) and demonstrate different points of view. Staff prefers its approach for the following reasons: 1) both Staff's and SSVEC's proposed base commodity tariff rates exclude a purchased power adjustor; 2) Staff's approach compares present and proposed base commodity rates that only include the base cost of power plus O&M-related costs that make up the total base commodity tariff rate; 3) although the existing WPCA may be set to zero in this rate case, nothing prevents the Cooperative from requesting an increase to the WPCA if the purchased power "bank" balance indicates an under collection; and, 4) Staff's exhibits WHM-1 and WHM-2 have been prepared in the same format as the exhibits submitted by Staff and accepted by the Commission in previous rate cases. Staff believes that it is better to have an unchanging rate when designing rates, because it is easier for customers to relate to rate increases that are not based on "moving targets".

Q. Will Staff's rate design testimony include further discussions about the cost of purchased power and the recovery of those costs?

A. Purchased power costs and their recovery will be discussed in direct testimony prepared by Julie McNeely-Kirwan.

Q. What does Staff recommend regarding its proposed rates?

A. Staff recommends that the rates proposed by Staff and summarized on WHM-2 be approved.

SERVICE-RELATED CHARGES

Q. Were there any service-related charge changes proposed by Sulphur Springs?

A. Yes.

Q. What does Staff recommend regarding Sulphur Springs' proposed changes to its service-related charges?

A. Staff's recommendations are summarized at page 2 of WHM-2. The rates proposed for these services are expected to increase revenues from $603,308 to $948,965 per year. The increase in the amount of $344,965 is overall approximately 57 percent. Staff did not accept the Cooperative's proposed service fees because the increases were higher than increases developed by Staff. The basis for Staff's recommendations is the increase in labor rates for the service sector in the Arizona region as reported in the Handy-Whitman index over the fifteen year period ended December 31, 2007 – the Test Year in this docket. Staff believes that this is a reliable, accurate source to base its recommendations upon.

UNBUNDLED TARIFFS

Q. Please discuss Sulphur Springs' unbundled tariffs.

A. The Cooperative's unbundled rates are not broken down into categories that would be sufficient to offer customers "Transportation" billings should they be desirable rate options for customers in the future. For example, the Residential "unbundled" rates submitted by SSVEC contain only two categories: 1) Power Supply and 2) SSVEC Wires. What would typically be expected under in an open access market would be the monthly customer charge further broken down into the following charges: a service availability charge, a metering charge, a meter reading charge, a billing charge and an information and service charge. The commodity rate is further broken down into the following components: a distribution delivery charge, a transmission delivery charge, an energy charge, a demand charge and a transmission charge. The energy charge, demand charge and transmission charge components of the commodity rate should reflect Sulphur Springs' cost to provide energy received from its power sources. If the Cooperative's territory is open to competition, a customer opting to take service from a competitive generation provider would not pay the energy charge, demand charge and transmission charge components of the commodity rate to Sulphur Springs.

Q. What does Staff recommend regarding unbundled rates for Sulphur Springs?

A. Staff recommends that the proposed unbundled rates be approved. However, Staff recommends that in future rate case filings that Sulphur Springs be required to develop more detailed and conventional unbundled rates that are structured to not result in any incentive or disincentive for customers who want to choose competitive generation suppliers.

MISCELLANEOUS TARIFF MATTER - BILL ESTIMATION PROCEDURES

Q. Does Staff wish to address any additional issues related to the rate case proceeding?

A. Yes. The provisions in Sulphur Springs' rules and regulations do not contain detailed and specific bill estimation procedures that would be implemented in cases where SSVEC is unable to obtain actual meter reads. In recent decisions before the Commission, applicants were ordered to file separate tariffs describing their bill estimation methodologies.

Q. What does Staff recommend regarding Sulphur Springs's bill estimation procedures?

A. Staff recommends that SSVEC submit through Docket Control a separate tariff describing its bill estimation methodologies for Commission approval within thirty days of a decision in this matter. The tariff should address, but not be limited to, the following terms and conditions:

a. Conditions under which estimated bills will be billed to customers.

b. Notice of estimation clearly noted on estimated bills that are rendered to customers.

c. Estimation procedures that explicitly address the conditions and procedures for estimated bills such as kWh estimates where: i) at least one year of premise history exists for the same customer at the same premise or a new customer with at least one year of premise history; ii) less than one year of premise history for the same customer at the same premise exists; iii) less than one year of premise history exists for a new customer but some premise history exists for the new customer; and, iv) no prior consumption history exists.

d. Variations in estimation methods for differing conditions such as cases involving meter tampering or damaged meters.

e. Conditions where bill estimations will be developed automatically or manually.

f. Conditions where special procedures may be required such as the installation of meters with automatic reading capabilities, the need to estimate first and final bills, and the requirement to use customer specific data to complete an estimate.

g. Where applicable, clearly indicate that estimation procedures will be in compliance with the appropriate section of the Arizona Administrative Code [e.g. Section R14-2-210(A)].

Q. Does this conclude your testimony?

A. Yes.

Rate Design
(Docket No. E-01575A-08-0328)

	Calculated Present	Staff Proposed	SSVEC Present Revenues	Staff Proposed Revenues	$ Delta	% Delta
Residential Non-TOU						
Monthly Customer Charge:	$7.50	$8.25	$3,639,600	$4,003,560	$363,960	10.00%
Cost Per KWh: First 750	$0.09850	$0.11818				
Cost Per KWh: Over 750	$0.09384	$0.11818				
Total Kwh Used: First 750:?	259,719,236	259,719,236	$25,582,345	$30,693,560	$5,111,215	19.98%
Total Kwh Used: Over 750:	93,448,498	93,448,498	$8,769,207	$11,043,722	$2,274,515	25.94%
Kwhs in Minimun:	0	0	0	0		
Total Billings:	485,280	485,280				
Subtotal (kWh and $)	353,167,734		$37,991,152	$45,740,842	$7,749,690	20.40%
WPCA			$4,664,734	$33	($4,664,701)	-100.00%
Total Revenue			$42,655,886	$45,740,875	$3,084,989	7.23%

	Calculated Present	Staff Proposed	Present Revenues	Proposed Revenues	$ Delta	% Delta
Residential - TOU						
Monthly Customer Charge:	$11.40	$13.25	$2,371	$2,756	$385	16.23%
Cost Per KWh: On-Peak	$0.14050	$0.13477				
Cost Per KWh: Off-Peak	$0.07319	$0.09841				
Total Kwh Used: On-Peak	43,805	43,805	$6,155	$5,904	($251)	-4.08%
Total Kwh Used: Off-Peak	166,197	166,197	$12,164	$16,356	$4,192	34.46%
Kwhs in Minimun:	0	0	0	0		
Total Billings:	208	208				
Subtotal (kWh and $)	210,002	210,002	$20,690	$25,015	$4,326	20.91%
WPCA			$2,797	$0	($2,797)	-100.00%
Total Revenue			$23,487	$25,015	$1,529	6.51%

	Calculated Present	Staff Proposed	Present Revenues	Proposed Revenues	$ Delta	% Delta
General Service Non-Demand						
Monthly Customer Charge:	$11.50	$13.50	$866,698	$1,017,428	$150,730	17.39%
Cost Per KWh	$0.08780	$0.11449				
Total Kwh Used	36,407,984	36,407,984	$3,196,621	$4,168,291	$971,670	30.40%
Added Minimum	$ 35,996	35,996	$ 35,996	$35,996	$0	0.00%
Kwhs in Minimun:	0	0	0	0		
Total Billings:	75,365	75,365				
Subtotal (kWh and $)	36,407,984		$4,099,314	$5,221,714	$1,122,400	27.38%
WPCA			$487,226	$3	($487,223)	-100.00%
Total Revenue			$4,586,540	$5,221,717	$635,177	13.85%

	Calculated Present	Staff Proposed	Present Revenues	Proposed Revenues	$ Delta	% Delta
General Service Demand						
Monthly Customer Charge:	$11.50	$13.35	$286,201	$332,241	$46,041	16.09%
Demand > 10 kW	$8.50	$7.45				
Demand > 10 kW Units	170,742	170,742	$1,109,823	$1,272,028	$162,205	14.62%
Cost Per KWh:	$0.08780	$0.11316				
Total Kwh Used	70,960,271	70,960,271	$6,230,312	$8,029,740	$1,799,428	28.88%
Added Minimum	$27,251	$27,251	$27,251	$27,251	$0	0.00%
Total Billings:	24,887	24,887				
Subtotal (kWh and $)	70,960,271		$7,653,586	$9,661,261	$2,007,674	26.23%
WPCA	$944,118	$7	$944,118	$7	($944,111)	-100.00%
Total Revenue			$ 8,597,704	$ 9,661,268	$1,063,563	12.37%

	Calculated Present	Staff Proposed	Present Revenues	Proposed Revenues	$ Delta	% Delta
General Service TOU						
Monthly Customer Charge:	$12.75	$14.45	$6,299	$7,138	$840	13.33%
Demand > 10 kW	$17.00	$18.50				
Demand > 10 kW Units	1,189	1,189	$20,213	$21,997	$1,784	8.82%
Cost Per KWh:	$0.06739	$0.08727				
Total Kwh Used	836,583	836,583	$56,377	$73,007	$16,629	29.50%
Added Minimum	$0	$0	$0	$0	$0	0.00%
Total Billings:	494	494				
Subtotal (kWh and $)	836,583		$82,889	$102,141	$19,253	23.23%
WPCA	$10,403	$0	$10,403	$0	($10,403)	-100.00%
Total Revenue			$ 93,292	$ 102,141	$8,850	9.49%

	Calculated Present	Staff Proposed	Present Revenues	Proposed Revenues	$ Delta	% Delta
Irrigation Seasonal						
Monthly Customer Charge:	$25.00	$25.00	$75,850	$75,850	$0	0.00%
Demand Cost	$6.50	$6.80				
Demand Units	122,093	122,093	$793,605	$830,232	$36,628	4.62%
Cost Per KWh:	$0.06590	$0.08436				
Cost Winter kWh <= 300	$0.09290	$0.11076				
Cost Winter kWh > 300	$0.06590	$0.08388				
Summer Kwh Used	29,090,785	29,090,785	$1,917,083	$2,454,065	$536,982	28.01%
<= 300 Winter kWh	7,879,053	7,879,053	$731,964	$872,723	$140,759	19.23%
> 300 Winter kWh	809,740	809,740	$53,362	$67,920	$14,558	27.28%
Total Billings:	3,034	3,034				
Subtotal (kWh and $)	37,779,578		$3,571,863	$4,300,791	$728,928	20.41%
WPCA	$488,409	$0	$488,409	$0	($488,409)	-100.00%
Total Revenue			$ 4,060,272	$ 4,300,791	$240,519	5.92%

	Calculated Present	Staff Proposed	Present Revenues	Proposed Revenues	$ Delta	% Delta
Irrigation Load Factor						
Monthly Customer Charge:	$30.00	$30.00	$9,600	$9,600	$0	0.00%
Cost Per KWh:	$0.06800	$0.09036				
Total Kwh Used	16,244,584	16,244,584	$1,104,632	$1,467,893	$363,261	32.89%
Added kW Minimum	$ 155,389	155,389	$ 155,389	$ 155,389	$0	0.00%
Kwhs in Minimun:	0	0	0	0		
Total Billings:	320	320				
Subtotal (kWh and $)	16,244,584		$1,269,621	$1,632,882	$363,261	28.61%
WPCA	$ 199,884	$ 1	$199,884	$1	($199,883)	-100.00%
Total Revenue			$1,469,505	$1,632,883	$163,378	11.12%

Rate Design
(Docket No. E-01575A-08-0328)

Irrigation Daily			Present Revenues	Proposed Revenues	$ Delta	% Delta
Monthly Customer Charge:	$25.00	$25.00	$21,825	$21,825	$0	0.00%
First 150 kWh Cost	$0.09290	$0.10624				
Next 150 kWh Cost	$ 0.08950	$0.10288				
Over 300 kWh Cost	$0.06450	$0.07782				
First 150 kWh	2,006,488	2,006,488	$186,403	$213,174	$26,771	
Next 150 kWh	587,056	587,056	$52,542	$60,399	$7,858	
Over 300 kWh	3,472,041	3,472,041	$223,947	$270,208	$46,261	
Discounted First 150	2,258,126	2,258,126	$169,922	$199,810	$29,888	
Discounted Next 150	2,258,126	2,258,126	$163,703	$193,651	$29,948	
Discounted Rate First	$ 0.075249	$0.08848			$140,726	
Discounted Rate Second	$ 0.072495	$0.08576				
Total Billings:	873	873				
Subtotal (kWh and $)	10,581,837		$818,340	$959,066	$140,726	17.20%
WPCA	$136,644	$0	$136,644	$0	($136,644)	-100.00%
Total Revenue			$ 954,984	$ 959,066	$4,082	0.43%

Irrigation Weekly			Present Revenues	Proposed Revenues	$ Delta	% Delta
Monthly Customer Charge:	$25.00	$25.00	$65,925	$65,925	$0	0.00%
First 150 kWh Cost	$0.09290	$0.10909				
Next 150 kWh Cost	$ 0.08950	$0.10624				
Over 300 kWh Cost	$0.06450	$0.08029				
First 150 kWh	7,050,188	7,050,188	$654,962	$769,092	$114,130	
Next 150 kWh	1,989,408	1,989,408	$178,052	$211,350	$33,298	
Over 300 kWh	10,810,048	10,810,048	$697,248	$867,970	$170,722	
Discounted First 150	6,465,208	6,465,208	$558,575	$663,990	$105,416	
Discounted Next 150	6,465,208	6,465,208	$538,132	$647,618	$109,486	
Discounted Rate First	$ 0.086397	$0.10270			$533,052	
Discounted Rate Second	$ 0.083235	$0.10017				
Total Billings:	2,637	2,637				
Subtotal (kWh and $)	32,780,060		$2,692,894	$3,225,946	$533,052	19.79%
WPCA	$413,219	$3	$413,219	$3	($413,216)	-100.00%
Total Revenue			$ 3,106,113	$ 3,225,949	$119,836	3.86%

Irrigation Daily/Large			Present Revenues	Proposed Revenues	$ Delta	% Delta
Monthly Customer Charge:	$25.00	$25.00	$36,550	$36,550	$0	0.00%
kWh Cost	$0.06800	$0.08368				
Total kWh	35,167,187	35,167,187	$2,391,369	$2,942,616		
Added Minimum	$ 102,601	$ 102,601	$ 102,601	$ 102,601		
Total Billings:	1,462	1,462				
Subtotal (kWh and $)	35,167,187		$2,530,520	$3,081,767	$551,247	21.78%
WPCA	$449,741	$3	$449,741	$3	($449,738)	-100.00%
Total Revenue			$ 2,980,261	$ 3,081,770	$101,509	3.41%

Irrigation Test			Present Revenues	Test $ moved to Sch. GS Proposed Revenues	$ Delta	% Delta
Monthly Customer Charge:	$0.00	$0.00	$0	$0	$0	0.00%
kWh Cost	$0.08780	$0.11830				
Total kWh	21,603	21,603	$1,897	$0		
Added Minimum	$ -	$ -	$ -	$ -		
Total Billings:	1	1				
Subtotal (kWh and $)	21,603		$1,897	$0	($1,897)	-100.00%
WPCA	$273	$0	$273	$0	($273)	-100.00%
Total Revenue			$ 2,170	$ -	$0	0.00%

Large Power			Present Revenues	Proposed Revenues	$ Delta	% Delta
Monthly Customer Charge:	$42.00	$44.25	$163,254	$172,000	$8,746	5.36%
kWh Cost	$0.06210	$0.07716				
kW Cost	$6.50	$6.80				
Total kWh	124,127,579	124,127,579	$7,708,323	$9,577,213	$1,868,890	
Total kW	447,436	447,436	$ 2,908,334	$ 3,042,565	$134,231	
Total Billings:	3,887	3,887				
Subtotal (kWh and $)	124,127,579		$10,779,911	$12,791,778	$2,011,867	18.66%
WPCA	$1,654,110	$11	$1,654,110	$11	($1,654,099)	-100.00%
Total Revenue			$ 12,434,021	$ 12,791,789	$357,768	2.88%

Large Power Seasonal			Present Revenues	Proposed Revenues	$ Delta	% Delta
Monthly Customer Charge:	$50.00	$56.25	$2,600	$2,925	$325	12.50%
kWh Cost	$0.05940	$0.08				
kW Cost Cust.-Owned T	$7.00	$7.85				
kW Cost Coop.-Owned T	$8.50	$9.40				
Total kWh	1,073,769	1,073,769	$63,782	$83,634	$19,852	
Total kW Cust. Owned T	8,364.98	8,364.98	$ 58,555	$ 65,665	$7,110	
Total kW Coop. Owned T	877.60	877.60	$ 7,460	$ 8,249	$790	
Total Billings:	52	52				
Subtotal (kWh and $)	1,073,769		$132,396	$160,473	$28,077	21.21%
WPCA	$12,216	$0	$12,216	$0	($12,216)	-100.00%
Total Revenue			$ 144,612	$ 160,473	$15,861	10.97%

Large Power Industrial			Present Revenues	Proposed Revenues	$ Delta	% Delta
Monthly Customer Charge:	$225.00	$233.50	$17,775	$18,447	$672	3.78%
kWh Cost < = 400	$0.06100	$0.07675				
kWh Cost > 400	$0.03300	$0.04761				
kW Cost Cust.-Owned T	$5.50	$5.75				
kW Cost Coop.-Owned T	$6.00	$6.25				
Total kWh < = 400	23,299,814	23,299,814	$1,421,289	$1,788,244	$366,955	
Total kWh > 400	1,731,577	1,731,577	$57,142	$82,441	$25,299	
Total kW Cust. Owned T	6,003.00	6,003.00	$ 33,017	$ 34,517	$1,501	
Total kW Coop. Owned T	61,242.00	61,242.00	$ 367,452	$ 382,763	$15,311	
Total Billings:	79	79				
Subtotal (kWh and $)	25,031,391		$1,896,674	$2,306,411	$409,737	21.60%
WPCA	$336,234	$2	$336,234	$2	($336,232)	-100.00%
Total Revenue			$ 2,232,908	$ 2,306,413	$73,505	3.29%

Rate Design
(Docket No. E-01575A-08-0328)

			Present Revenues	Proposed Revenues	$ Delta	% Delta
Large Power TOU						
Monthly Customer Charge:	$43.84	$44.45	$20,079	$20,358	$279	1.39%
On-Peak kW Cost	$17.00	$17.15				
Off-Peak kW Cost	$4.09	$4.15				
On-Peak kW Billings	2,007	2,007	$34,119	$34,420	$301	0.88%
Off-Peak kW Billings	49,795	49,795	$203,662	$206,649	$2,988	1.47%
kWh Cost	$ 0.03469	$0.04788				
Total kWh	8,528,086	8,528,086	$295,839	$408,286	$112,446	38.01%
Total Billings	458	458				
Subtotal (kWh and $)	8,528,086		$553,699	$669,713	$116,014	20.95%
WPCA			$107,481	$1	($107,480)	-100.00%
Total Revenue			$ 661,180	$ 669,714	$ 8,534	1.29%
Large Power Contract 1			**Present Revenues**	**Proposed Revenues**	**$ Delta**	**% Delta**
Monthly Customer Charge:	$25.00	$25.00	$300	$300	$0	0.00%
On-Peak kW Cost	$2.50	$2.50				
On-Peak kWh Cost	$0.05820	$0.07145				
Off-Peak kWh Cost	$0.03500	$0.04825				
On-Peak kW Billings	84,291	84,291	$210,728	$210,728	$0	0.00%
On-Peak kWh Billings	16,120,800	16,120,800	$938,231	$1,151,871	$213,640	22.77%
Off-Peak kWh Billings	7,354,800	7,354,800	$257,418	$354,876	$97,458	
Total kWh	23,475,600	23,475,600			$311,099	
Total Billings	12	12				
Subtotal (kWh and $)	23,475,600		$1,406,676	$1,717,775	$311,099	22.12%
WPCA	$296,760	$ 2.00	$296,760	$2	($296,758)	-100.00%
Total Revenue			$ 1,703,436	$ 1,717,777	$ 14,341	0.84%
Large Power Contract 2			**Present Revenues**	**Proposed Revenues**	**$ Delta**	**% Delta**
Monthly Customer Charge:	$9,633.00	$9,633.00	$115,596	$115,596	$0	0.00%
Billing kW Cost	$9.00	$9.00				
Billing kW Units	24,792	24,792	$ 223,128	$ 223,128	$0	0.00%
First 400 kWh Cost	$0.0548	$0.0684				
Over 400 kWh Cost	$ 0.03475	$0.0484				
First 400 kWh Units	9,916,800	9,916,800	$542,945	$677,900	$134,955	24.86%
Over 400 kWh Units	4,497,600	4,497,600	$156,292	$217,479	$61,187	
Total Billings	12	12				
Subtotal (kWh and $)	14,414,400		$1,037,960	$1,234,103	$196,142	18.90%
WPCA	$195,990	$ 1.00	$195,990	$1	($195,989)	-100.00%
Total Revenue			$ 1,233,950	$ 1,234,104	$ 153	0.01%
RV Parks			**Present Revenues**	**Proposed Revenues**	**$ Delta**	**% Delta**
Monthly Customer Charge:	$ 42.00	$43.55	$5,964	$6,184	$220	3.69%
Monthly Billings	142	142				
kW Cost	$ 6.50	$6.70				
kw Units	14,932	14,932	$97,058	$100,044	$2,986	3.08%
kWh Cost	$ 0.0621	$ 0.0766				
kWh Units	4,675,120	4,675,120	$290,325	$358,288	$67,963	23.41%
Subtotal			$393,347	$464,517	$71,170	18.09%
WPCA	$ 63,520	$0	$63,520	$0		
Total Revenue			$456,867	$464,517	$7,650	1.67%

Street Lights

Units	Present Rates	Proposed Rates	Present Revenues *	Proposed Revenues *	$ Delta	% Delta
			$ 32,344	$0	($32,344)	-100.00%
168	$9.85	$12.31	$1,655	$2,068	$413	24.97%
1,392	$8.95	$11.19	$12,458	$15,576	$3,118	25.03%
1,608	$11.25	$15.97	$18,090	$25,680	$7,590	41.96%
24	$16.55	$20.69	$397	$497	$99	25.02%
24	$18.40	$23.00	$442	$552	$110	25.00%
756	$10.35	$12.94	$7,825	$9,783	$1,958	25.02%
780	$12.55	$15.69	$9,789	$12,238	$2,449	25.02%
126	$18.70	$23.38	$2,356	$2,946	$590	25.03%
12	$20.50	$25.63	$246	$308	$62	25.02%
3,696	$11.75	$14.69	$43,428	$54,294	$10,866	25.02%
2,940	$14.15	$17.69	$41,601	$52,009	$10,408	25.02%
12	$22.10	$27.63	$265	$332	$66	25.02%
84	$24.10	$30.13	$2,024	$2,531	$507	25.02%
90	$13.35	$16.69	$1,202	$1,502	$301	25.02%
1,260	$15.80	$19.75	$19,908	$24,885	$4,977	25.00%
0	$24.80	$31.00	$0	$0	$0	0.00%
12	$26.80	$33.50	$322	$402	$80	25.00%
765	$16.45	$20.56	$12,584	$15,728	$3,144	24.98%
3,012	$18.65	$23.31	$56,174	$70,210	$14,036	24.99%
0	$31.40	$39.25	$0	$0	$0	0.00%
108	$33.00	$41.25	$3,564	$4,455	$891	25.00%

* First entry is WPCA

Rate Design
(Docket No. E-01575A-08-0328)

Street Lights	Units	Present Rates	Proposed Rates	Present Revenues	Proposed Revenues	$ Delta	% Delta
	144	$18.55	$23.19	$2,671	$3,339	$668	25.01%
	144	$20.75	$25.94	$2,988	$3,735	$747	25.01%
	288	$35.25	$44.06	$10,152	$12,689	$2,537	24.99%
	12	$36.90	$46.13	$443	$554	$111	25.01%
	10	$6.90	$8.63	$69	$86	$17	25.07%
	2,400	$8.15	$10.19	$19,560	$24,456	$4,896	25.03%
	0	$13.25	$16.56	$0	$0	$0	0.00%
	0	$14.05	$17.56	$0	$0	$0	0.00%
	36	$8.20	$10.25	$295	$369	$74	25.00%
	1,584	$9.35	$11.69	$14,810	$18,517	$3,707	25.03%
	126	$15.30	$19.13	$1,928	$2,410	$483	25.03%
	0	$16.10	$20.13	$0	$0	$0	0.00%
	132	$9.25	$11.56	$1,221	$1,526	$305	24.97%
	8,316	$10.50	$13.13	$87,318	$109,189	$21,871	25.05%
	0	$17.65	$22.06	$0	$0	$0	0.00%
	216	$18.60	$23.25	$4,018	$5,022	$1,004	25.00%
	60	$10.75	$13.44	$645	$806	$161	25.02%
	1,776	$12.05	$15.06	$21,401	$26,747	$5,346	24.98%
	0	$19.70	$24.63	$0	$0	$0	0.00%
	24	$21.20	$26.56	$509	$637	$129	25.28%
	648	$13.50	$16.88	$8,748	$10,938	$2,190	25.04%
	1,668	$14.60	$18.25	$24,353	$30,441	$6,088	25.00%
	0	$26.25	$32.81	$0	$0	$0	0.00%
	0	$26.70	$33.38	$0	$0	$0	0.00%
	12	$15.55	$19.44	$187	$233	$47	25.02%
	48	$16.65	$20.81	$799	$999	$200	24.98%
	0	$30.20	$37.75	$0	$0	$0	0.00%
	0	$30.45	$38.06	$0	$0	$0	0.00%
	34,513			$468,788	$548,690	$79,902	17.04%
						$79,902	
	2,355,546	(see Sch. F-6.0)					

Security Lights	Units	Present Rates	Proposed Rates	Present Revenues	Proposed Revenues	$ Delta	% Delta
	2,188	$9.50	$11.40	$20,786	$24,943	$4,157	20.00%
	21,664	$9.10	$10.92	$197,142	$236,571	$39,428	20.00%
	3,445	$7.35	$8.82	$25,321	$30,385	$5,064	20.00%
num				$21,404	$21,404	$0	0.00%
	1,634,628	(see Sch. F-6.0)					
				$264,653	$313,303	$48,650	18.38%
				$22,429	$0	($22,429)	-100.00%
				$287,082	$313,303	$26,221	9.13%

Unmetered Power	Units			Present Revenues	Proposed Revenues	$ Delta	% Delta
	2,352	$11.00	$16.00	$25,872	$37,632	$11,760	45.45%
	386,616	$0.096000	$0.08730	$37,115	$33,752	($3,364)	-9.06%
				$62,987	$71,384	$8,396	13.33%
				$5,305	$0	($5,305)	-100.00%
				$68,292	$71,384	$3,091	4.53%

Pre meter Construction	Units			Present Revenues	Proposed Revenues	$ Delta	% Delta
	138	$11.50	$12.00	$1,587	$1,656	$69	4.35%

			(1) Present Revenues	(2) Proposed Revenues	(3) $ Delta	
nt, Proposed & Delta $ using Staff's calculations---->			$88,222,937	$94,231,226	$6,008,289	6.81%
		Targets--->	88,525,803	94,534,633	$6,008,830	6.79%
	51,489	Differences--->	($302,866)	($303,407)	($541)	
	799,860,156					

Rate Design
Sulphur Springs Valley Electric Cooperative
Docket No. E-01575A-08-0328
Test Year Ended December 31, 2007

	Present Rates	Proposed Rates			
		Company	% Change	Staff	% Change
MONTHLY MINIMUM CHARGE					
Residential	$7.50	$12.50	66.7%	$8.25	10.0%
Residential (TOU)	$11.40	$16.50	44.7%	$13.25	16.2%
General Service (Non-Demand)	$11.50	$17.50	52.2%	$13.50	17.4%
General Service (Demand)	$11.50	$17.50	52.2%	$13.35	16.1%
General Service (TOU)	$12.75	$21.50	68.6%	$14.45	13.3%
Irrigation Seasonal	$25.00	$25.00	0.0%	$25.00	0.0%
Irrigation Load Factor	$30.00	$30.00	0.0%	$30.00	0.0%
Irrigation Daily	$25.00	$25.00	0.0%	$25.00	0.0%
Irrigation Weekly	$25.00	$25.00	0.0%	$25.00	0.0%
Irrigation Daily/Large	$25.00	$25.00	0.0%	$25.00	0.0%
Large Power	$42.00	$75.00	78.6%	$44.25	5.4%
Large Power Seasonal	$50.00	$75.00	50.0%	$56.25	12.5%
Large Power Industrial	$225.00	$250.00	11.1%	$233.50	3.8%
Large Power TOU	$43.84	$100.00	128.1%	$44.45	1.4%
Large Power Contract 1	$25.00	$25.00	0.0%	$25.00	0.0%
Large Power Contract 2	$9,633.00	$9,633.00	0.0%	$9,633.00	0.0%
RV Parks	$42.00	$75.00	78.6%	$43.55	3.7%
Street Lighting and Security Lighting		See Schedule WHM-1, PP. 3-4 for Details			
Unmetered Power	$11.00	$16.00	45.5%	$16.00	45.5%
Pre-Meter Construction	$11.50	$12.00	4.3%	$12.00	4.3%
ENERGY (kWh) and Demand (kW) Rates					
Residential First 750 kWh	$0.09850	$0.11830	20.1%	$0.11818	20.0%
Residential Over 750 kWh	$0.09384	$0.11830	26.1%	$0.11818	25.9%
Residential (On-peak TOU)	$0.14050	$0.18700	33.1%	$0.13477	-4.1%
Residential (Off-Peak TOU)	$0.07319	$0.07800	6.6%	$0.09841	34.5%
General Service (Non-Demand)	$0.08780	$0.11830	34.7%	$0.11449	30.4%
General Service (Energy)	$0.08780	$0.11830	34.7%	$0.11316	28.9%
General Service (Demand)	$6.50000	$9.00000	38.5%	$7.45000	14.6%
General Service (TOU)-Energy	$0.06739	$0.08830	31.0%	$0.08727	29.5%
General Service (TOU)-Demand	$17.00000	$19.00000	11.8%	$18.50000	8.8%
Irrigation Seasonal-Energy	$0.06590	$0.08470	28.5%	$0.08436	28.0%
Irrigation Seasonal- Winter Energy (First 300 kWh)	$0.09290	$0.11000	18.4%	$0.11076	19.2%
Irrigation Seasonal- Winter Energy (Over 300 kWh)	$0.06590	$0.08000	21.4%	$0.08388	27.3%
Irrigation Seasonal-Demand	$6.50000	$8.00000	23.1%	$6.80000	4.6%
Irrigation Load Factor-Energy	$0.06800	$0.09570	40.7%	$0.09036	32.9%
Irrigation Daily First 150 kWh	$0.09290	$0.11000	18.4%	$0.10624	14.4%
Irrigation Daily Next 150 kWh	$0.08950	$0.11000	22.9%	$0.10288	14.9%
Irrigation Daily Over 300 kWh	$0.06450	$0.08000	24.0%	$0.07782	20.7%
Irrigation Weekly First 150 kWh	$0.09290	$0.11000	18.4%	$0.10909	17.4%
Irrigation Weekly Next 150 kWh	$0.08950	$0.11000	22.9%	$0.10624	18.7%
Irrigation Weekly Over 300 kWh	$0.06450	$0.08000	24.0%	$0.08029	24.5%
Irrigation Daily/Large kWh	$0.06800	$0.08500	25.0%	$0.08368	23.1%
Irrigation Daily/Large kW (Zero Billing Units Submitted)	$16.00000	$19.00000	18.8%	$0.00000	-100.0%
Large Power kWh	$0.06210	$0.06760	8.9%	$0.07716	24.3%
Large Power Kw	$6.50000	$9.80000	50.8%	$6.80000	4.6%
Large Power Seasonal kWh	$0.05940	$0.06760	13.8%	$0.08000	34.7%
Large Power Seasonal kW (Customer Owned Trans)	$7.00000	$9.80000	40.0%	$7.85000	12.1%
Large Power Seasonal kW (Coop. Owned Trans)	$8.50000	$10.80000	27.1%	$9.40000	10.6%

Large Power Industrial Energy-First 400kWh	$0.06100	$0.07630	25.1%	$0.07675	25.8%
Large Power Industrial Energy-Over 400kWh	$0.03300	$0.04130	25.2%	$0.04761	44.3%
Large Power Industrial kW (Customer Owned Trans)	$5.50000	$6.50000	18.2%	$5.75000	4.5%
Large Power Industrial kW (Coop. Owned Trans)	$6.00000	$7.50000	25.0%	$6.25000	4.2%
Large Power TOU Energy	$0.03469	$0.04070	17.3%	$0.04788	38.0%
Large Power TOU On Peak kW	$17.00000	$19.00000	11.8%	$17.15000	0.9%
Large Power TOU Off Peak kW	$4.09000	$4.75000	16.1%	$4.15000	1.5%
Large Power Contract 1 On-Peak Energy	$0.05820	$0.07100	22.0%	$0.07145	22.8%
Large Power Contract 1 Off-Peak Energy	$0.03500	$0.04780	36.6%	$0.04285	22.4%
Large Power Contract 1 kW	$2.50000	$2.50000	0.0%	$2.50000	0.0%
Large Power Contract 2 First 400 kWh	$0.05475	$0.06910	26.2%	$0.06836	24.9%
Large Power Contract 2 Over 400 kWh	$0.03475	$0.04910	41.3%	$0.04835	39.1%
Large Power Contract 2 kW	$9.00000	$9.00000	0.0%	$9.00000	0.0%
RV Parks kWh	$0.06210	$0.06760	8.9%	$0.07660	23.3%
RV Parks kW (Coop. Owned Trans.)	$6.50000	$9.80000	50.8%	$6.70000	3.1%
Street Lighting and Security Lighting		See Schedule WHM-1, PP. 3-4 for Details			
Unmetered Power (kWh)	$0.09600	$0.08730	-9.1%	$0.08730	-9.1%
Pre-Meter Construction		No Energy Rates			
PURCHASED POWER FUEL ADJUSTOR - PER KWH					
All Customer Classes (Average Adjustor)	$0.013157	$0.00000	-100.0%	$0.00000	-100.0%
Note: Base cost of power to increase $0.013157 raising it from $0.058970 to $0.072127.					
SERVICE RELATED CHARGES					
Existing Member Conn. Fees - Normal Hrs.	$25.00	$50.00	100%	$40.00	60%
Existing Member Conn. Fees - After Hrs.	$45.00	$150.00	233%	$75.00	67%
New Connects	$0.00	$50.00	100%	$40.00	100%
Non-Pay Fee - Normal Hours	$25.00	$50.00	100%	$40.00	60%
Non-Pay Fee - After Hours	$45.00	$150.00	233%	$75.00	67%
Radio Control Installation Fee	$125.00	$125.00	0%	$125.00	0%
Temporary Meter	$95.00	$95.00	0%	$95.00	0%
Special After Hours Connection Fee	$620.00	$620.00	0%	$620.00	0%
NSF Return Check Fee	$15.00	$35.00	133%	$25.00	67%
Meter Rereads	$20.00	$50.00	150.0%	$35.00	75%
Service Call Regular Hours	$25.00	$100.00	300%	$40.00	60%
Service Call After Hours	$45.00	$150.00	233%	$75.00	67%
Meter Test	$25.00	$150.00	500%	$40.00	60%

Typical Bill Analysis
Sulphur Springs Valley Electric Cooperative
Docket No. E-01575A-08-0328
Test Year Ended December 31, 2007

TYPICAL BILL ANALYSIS

COMPANY PROPOSED

Customer Class	Average kWh Per Month	Present Rates	Company Proposed Rates	Dollar Increase	Percent Increase
Residential	728	$78.31	$98.62	$20.31	25.93%
Small Commercial	483	$53.91	$74.64	$20.73	38.46%
Large Commercial-Dem	2,854	$292.50	$397.25	$104.75	35.81%
Large Power (Coop. Trans)	31,884	$2,771.06	$3,359.71	$588.65	21.24%
100 W Security Lgt. (per lgt.)	60	$9.10	$10.92	$1.82	20.00%
150 W Street Lgt. (per lgt.)	54	$10.50	$13.13	$2.63	25.05%

STAFF PROPOSED

Customer Class	Average kWh Per Month	Present Rates	Staff Proposed Rates	Dollar Increase	Percent Increase
Residential	728	$78.31	$94.29	$15.97	20.40%
Small Commercial	483	$53.91	$68.80	$14.89	27.62%
Large Commercial-Dem	2,854	$292.50	$371.17	$78.67	26.90%
Large Power	31,884	$2,771.06	$3,288.05	$517.00	18.66%
100 W Security Lgt. (per lgt.)	60	$9.10	$10.92	$1.82	20.00%
150 W Street Lgt. (per lgt.)	54	$10.50	$13.13	$2.63	25.05%

RESIDENTIAL

		Company		Staff	
Monthly kWh Consumption	Present Rates	Proposed Rates	Percent Increase	Proposed Rates	Percent Increase
60	$13.34	$19.60	46.95%	15.34	15.03%
100	$17.23	$24.33	41.23%	20.07	16.49%
200	$26.95	$36.16	34.15%	31.89	18.30%
500	$56.14	$71.65	27.64%	67.34	19.96%
1000	$104.77	$130.80	24.84%	126.43	20.67%
1500	$153.41	$189.95	23.82%	185.52	20.93%
2000	$202.04	$249.10	23.29%	244.61	21.07%
2500	$250.68	$308.25	22.97%	303.70	21.15%
3000	$299.31	$367.40	22.75%	362.79	21.21%
4000	$396.58	$485.70	22.47%	480.97	21.28%
5000	$493.85	$604.00	22.30%	599.15	21.32%

Typical Bill Analysis
Sulphur Springs Valley Electric Cooperative
Docket No. E-01575A-08-0328
Test Year Ended December 31, 2007

TYPICAL BILL ANALYSIS - Continued

COMMERCIAL SMALL

Monthly kWh Consumption	Present Rates	Company Proposed Rates	Company Percent Increase	Staff Proposed Rates	Staff Percent Increase
60	16.77	24.60	46.70%	20.37	21.48%
120	22.04	31.70	43.84%	27.24	23.61%
2,000	187.10	254.10	35.81%	242.48	29.60%
4,000	362.70	490.70	35.29%	471.46	29.99%
5,000	450.50	609.00	35.18%	585.95	30.07%
10,000	889.50	1,200.50	34.96%	1,158.40	30.23%
15,000	1,328.50	1,792.00	34.89%	1,730.85	30.29%
20,000	1,767.50	2,383.50	34.85%	2,303.30	30.31%
25,000	2,206.50	2,975.00	34.83%	2,875.75	30.33%
30,000	2,645.50	3,566.50	34.81%	3,448.20	30.34%
35,000	3,084.50	4,158.00	34.80%	4,020.65	30.35%
40,000	3,523.50	4,749.50	34.79%	4,593.10	30.36%
45,000	3,962.50	5,341.00	34.79%	5,165.55	30.36%
50,000	4,401.50	5,932.50	34.78%	5,738.00	30.36%
100,000	8,791.50	11,847.50	34.76%	11,462.50	30.38%
150,000	13,181.50	17,762.50	34.75%	17,187.00	30.39%
200,000	17,571.50	23,677.50	34.75%	22,911.50	30.39%
250,000	21,961.50	29,592.50	34.75%	28,636.00	30.39%
300,000	26,351.50	35,507.50	34.75%	34,360.50	30.39%

COMMERCIAL LARGE

Monthly kWh Consumption	Present Rates	Company Proposed Rates	Company Percent Increase	Staff Proposed Rates	Staff Percent Increase
1,000	129.72	177.92	37.16%	161.38	24.40%
2,000	217.52	296.22	36.18%	274.54	26.21%
4,000	393.12	532.82	35.54%	500.86	27.41%
5,000	480.92	651.12	35.39%	614.02	27.68%
10,000	919.92	1,242.62	35.08%	1,179.82	28.25%
15,000	1,358.92	1,834.12	34.97%	1,745.62	28.46%
20,000	1,797.92	2,425.62	34.91%	2,311.42	28.56%
25,000	2,236.92	3,017.12	34.88%	2,877.22	28.62%
30,000	2,675.92	3,608.62	34.86%	3,443.02	28.67%
35,000	3,114.92	4,200.12	34.84%	4,008.82	28.70%
40,000	3,553.92	4,791.62	34.83%	4,574.62	28.72%
45,000	3,992.92	5,383.12	34.82%	5,140.42	28.74%
50,000	4,431.92	5,974.62	34.81%	5,706.22	28.75%
100,000	8,821.92	11,889.62	34.77%	11,364.22	28.82%
150,000	13,211.92	17,804.62	34.76%	17,022.22	28.84%
500,000	43,941.92	59,209.62	34.75%	56,628.22	28.87%
1,000,000	87,841.92	118,359.62	34.74%	113,208.22	28.88%
1,500,000	131,741.92	177,509.62	34.74%	169,788.22	28.88%

Typical Bill Analysis
Sulphur Springs Valley Electric Cooperative
Docket No. E-01575A-08-0328
Test Year Ended December 31, 2007

TYPICAL BILL ANALYSIS - Continued

LARGE POWER

Monthly kWh Consumption	Present Rates	Company Proposed Rates	Company Percent Increase	Staff Proposed Rates	Staff Percent Increase
25000	2,343.56	2,894.35	23.50%	2,756.88	17.64%
30000	2,654.06	3,232.35	21.79%	3,142.68	18.41%
35000	2,964.56	3,570.35	20.43%	3,528.48	19.02%
40000	3,275.06	3,908.35	19.34%	3,914.28	19.52%
45000	3,585.56	4,246.35	18.43%	4,300.08	19.93%
50000	3,896.06	4,584.35	17.67%	4,685.88	20.27%
55000	4,206.56	4,922.35	17.02%	5,071.68	20.57%
60000	4,517.06	5,260.35	16.46%	5,457.48	20.82%
65000	4,827.56	5,598.35	15.97%	5,843.28	21.04%
70000	5,138.06	5,936.35	15.54%	6,229.08	21.23%
75000	5,448.56	6,274.35	15.16%	6,614.88	21.41%

EXHIBIT
S-9
admitted

SURREBUTTAL

TESTIMONY

OF

WILLIAM MUSGROVE

DOCKET NO. E-01575A-08-0328

IN THE MATTER OF THE APPLICATION OF SULPHUR SPRINGS VALLEY ELECTRIC COOPERATIVE, INC. FOR A HEARING TO DETERMINE THE FAIR VALUE OF ITS PROPERTY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RETURN THEREON, TO APPROVE RATES DESIGNED TO DEVELOP SUCH RETURN AND FOR RELATED APPROVALS.

APRIL 10, 2009

BEFORE THE ARIZONA CORPORATION COMMISSION

KRISTIN K. MAYES
Chairman
GARY PIERCE
Commissioner
PAUL NEWMAN
Commissioner
SANDRA D. KENNEDY
Commissioner
BOB STUMP
Commissioner

IN THE MATTER OF THE APPLICATION OF SULPHUR SPRINGS VALLEY ELECTRIC COOPERATIVE, INC. FOR A HEARING TO DETERMINE THE FAIR VALUE OF ITS PROPERTY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RETURN THEREON, TO APPROVE RATES DESIGNED TO DEVELOP SUCH RETURN AND FOR RELATED APPROVALS.	DOCKET NO. E-01575A-08-0328

SURREBUTTAL

TESTIMONY

OF

WILLIAM MUSGROVE

ON BEHALF OF STAFF

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

APRIL 10, 2009

TABLE OF CONTENTS

ATTACHMENT

EXECUTIVE SUMMARY
STAFF SURREBUTTAL TESTIMONY
SULPHUR SPRINGS VALLEY ELECTRIC COOPERATIVE, INC.
(DOCKET NO. E-01575A-08-0328)

On June 30, 2008, Sulphur Springs Valley Electric Cooperative, Inc. ("SSVEC" or "Cooperative") filed with Docket Control its first general rate increase Application in almost 16 years. The Cooperative proposed a revenue increase in the amount of $10,881,590, or an increase of 11.75 percent. Staff recommends a $6,353,795, or 6.78 percent, revenue increase.

On February 17, 2009, Staff docketed its Direct testimony regarding revenue allocation and rate design, tariff changes, service charge fees, unbundled tariffs and the need for a bill estimation tariff.

On March 9, 2009, SSVEC docketed its Rebuttal testimony in which it identified three areas of disagreement with Staff's Direct testimony regarding rate design matters. Staff's Surrebuttal testimony responds to the Cooperative's Rebuttal testimony on the following issues:

1. SSVEC does not agree with Staff's recommended changes to customer charges and continues to support the higher customer charges originally proposed by SSVEC.

2. SSVEC believes that Staff's recommended rate for Residential Time-of-Use ("TOU") customers does not send the appropriate price signal and will be ineffective.

3. SSVEC has concluded that Staff's proposed service charge fees are not appropriate and do not reflect the actual cost of providing the services.

Staff's recommendations are summarized on pages 8-9 of its Surrebuttal testimony.

INTRODUCTION

Q. Please state your name, occupation, and business address.

A. My name is William Musgrove. My business address is 1200 West Washington Street, Phoenix, Arizona 85007.

Q. Will you briefly describe the nature of your work relationship with the Arizona Corporation Commission?

A. I am an independent contractor providing utilities consulting services to the Arizona Corporation Commission ("Commission" or "ACC") Utilities Division Staff ("Staff").

Q. Did you submit prepared Direct Testimony in this Docket on behalf of Staff?

A. Yes.

Q. Are there any changes in your Direct Testimony as docketed with the Commission on February 17, 2009?

A. Yes. Four typographical errors need to be corrected: (1) at page 3, line 9 the filed percent increases of 30 percent and 29 percent should be changed to 27 percent and 26 percent, respectively; (2) at page 5, line 22 the filed percent increase should be changed from 27.38 percent to 23.23 percent; (3) at page 10, line 20 the filed revenue in the amount of $948,965 should be changed to $948,273; and, (4) at WHM-1, p. 1 the proposed on-peak energy rate for residential TOU customers should be changed from $0.13477 per kWh to $0.16572 per kWh.

Q. Are there any other changes to your Direct Testimony?

A. No.

PURPOSE OF TESTIMONY

Q. What is the purpose of your Surrebuttal Testimony in this proceeding?

A. Staff will address the three rate design-related issues raised by Mr. David Hedrick in his rebuttal testimony filed on behalf of Sulphur Springs Valley Electric Cooperative, Inc. ("SSVEC" or "Cooperative"): (1) SSVEC does not agree with Staff's recommended changes to customer charges and continues to support the higher customer charges originally proposed by SSVEC; (2) SSVEC believes that Staff's recommended rate for Residential Time-of-Use ("TOU") customers does not send the appropriate price signal and will be ineffective; and, (3) SSVEC has concluded that Staff's proposed service charge fees are not appropriate and do not reflect the actual cost of providing the services.

CUSTOMER CHARGES

Q. Why has Staff recommended monthly customer charges that are generally lower than customer charges proposed by the Cooperative?

A. Staff's recommendations are driven and supported by data contained in the record and recognition of the impact of customer charge rate increases on rate payers. In addition, Staff did not lose sight of the fact that more than sixteen years will likely have passed since the last rate case before rates approved in this Docket are in effect. However, from rate payers' perspectives, it is impossible to implement conservation measures or more prudent utilization of energy to reduce fixed monthly customer charges. For example, if SSVEC's proposed increase to the residential customer charge was approved, residential customers would face an increase of nearly 67 percent to the fixed component of their monthly bills. Staff's proposed residential customer charge increase in the amount of 10 percent (Direct testimony, WHM-2, p. 1) is much more in line with Staff's overall proposed revenue increase of 6.78 percent (Direct testimony, Schedule CSB-1).

Q. Will Staff please explain how its recommended customer charges were designed in this Docket?

A. Staff's recommended customer charges are based upon three basic rate design principles. (1) The principle of gradualism is embodied in the discussion above and in the remaining rate classes' customer charges. Staff believes that it is unreasonable to expect customers' budgets to absorb increases that, excluding lighting, un-metered and pre-metered power, average 63.08 percent in one step. By comparison, Staff's recommended customer charge increases average 9.98 percent. Another consideration is that the Cooperative's proposed increase for residential customers would recover nearly 54 percent of customer charge-related costs that were accumulating over a fourteen-year period. Staff's recommended increase represents recovery of approximately 35 percent of customer charge-related costs, which Staff believes is a more reasonable pace toward recovery of SSVEC's costs. (2) Staff believes that a second rate design principle to consider is the fact that SSVEC requested an increase in total operating revenues in the amount of approximately $10.9 million (Schedule N-1.0) compared to Staff's recommended revenue increase in the amount of approximately $6.4 million (Schedule CSB-1). In designing its rates, Staff had to take into consideration the fact that SSVEC's proposed rates were designed to collect approximately $4.5 million, or 70 percent, more in operating revenues compared to Staff's $6.4 million rate design goals. (3) In light of the discussions above, Staff concluded that the most equitable allocation (a third rate design principle) of its proposed revenues was to honor the allocations proposed by the Cooperative, but with approximately $4.5 million less to allocate than was proposed by the Cooperative. Again, using the residential rate class as an example, approximately 12 percent of proposed revenues were allocated to the residential customer charge by SSVEC (Schedule N-2.0, p. 1) compared to the approximately 12 percent of proposed incremental revenues that Staff allocated to the residential customer charge (Direct testimony, WHM-1, p.1).

Q. What are Staff's recommendations regarding its proposed customer charges as they were designed in this Docket?

A. Supported by the discussions above, Staff recommends that its proposed customer charges be approved as originally filed.

RESIDENTIAL TOU RATE DESIGN

Q. Will Staff please discuss its proposed rate design for the residential TOU rate?

A. In reading Mr. Hedrick's Rebuttal testimony in preparation for Staff's Surrebuttal testimony, Staff recognized that an erroneous on-peak kWh rate was filed with Staff's Direct Testimony. WHM Surrebuttal Attachment 1 ("Attachment 1") corrects this error and increases the originally filed rate from $0.13477 per kWh to $0.16572 per kWh.

Q. Does the proposed revised increased rate for on-peak residential TOU sales necessitate any changes elsewhere in Staff's Direct Testimony?

A. No. Staff had originally designed incremental revenues for this customer class in the amount of $2,918. As is clearly shown on the schedule originally filed with its Direct testimony, (WHM-1, p. 1), the total base revenue increase is only $1,529, which is $1,389 short of Staff's original increase designed for the residential TOU class. A review of Staff's Surrebuttal Attachment 1 correctly depicts the total base revenue increase as $2,884 creating a de minimis shortfall in the amount of $34. The original $2,918 was derived based upon SSVEC's original $4,881 (Schedule N-1.0) incremental allocation (approximately .05 percent) to the Residential TOU class.

Q. Does the proposed revised rate for on-peak residential TOU sales address all of Mr. Hedrick's concerns regarding Staff's proposed residential TOU rates?

A. No. Although Staff's revised proposed on-peak $0.16572 per kWh rate is very close to SSVEC's revised $0.167010 per kWh (Surrebuttal testimony, Exhibit DH-13, page 1) proposed on-peak rate, Staff believes that the nearly 13 mill per on-peak kWh difference would move the on-peak rate issue behind SSVEC's three remaining concerns in the following order: (1) excluding SSVEC's customer charge concern that Staff has already addressed above, there remains a difference regarding the respective proposed off-peak kWh rate; (2) SSVEC and Staff disagree on the expected number of on-peak and off-peak residential TOU kWhs; and, (3) SSVEC and Staff disagree on the proposed inclusion of Sunday on-peak hours (1 p.m. through 7 p.m.) for residential TOU customers.

Q. What is the basis for Staff's proposed off-peak rate for residential TOU customers?

A. Staff's proposed $0.09841 per kWh off-peak rate is designed to recover approximately $2,005 in incremental base (excluding power costs) revenues, which represents approximately 79 percent of the $2,534 ($2,918 total allocation less $385 allocated to customer charge) remaining incremental base revenues to be allocated to residential TOU energy sales. As filed in the 2007 Test Year, 79 percent is the approximate ratio of off-peak sales compared to total residential TOU sales.

Q. Does Staff support the on-peak, off-peak kWh volumes proposed by SSVEC for the residential TOU rate class?

A. No. Staff recognizes that Mr. Hedrick estimates that nearly 35,000 off-peak kWhs will migrate to on-peak (approximately 21 percent) due primarily to "... the change in on peak hours, base charge and change in the standard residential rate." (response to Staff data request WM 10-1). As has been discussed above and will be discussed below, Staff does not support all of the changes proposed for on-peak hours, base charges and the standard residential rate proposed by SSVEC. Consequently, Staff believes that prospective on-peak, off-peak kWh residential TOU volumes will more closely conform to volumes originally reported in the 2007 Test Year (Direct testimony, WHM-1, p. 1) if Staff's recommendations are approved.

Q. Does Staff support the on-peak time periods proposed by SSVEC for the residential TOU rate class?

A. Not entirely. Staff is aware that summer and winter on-peak hours proposed by SSVEC are expected to increase from approximately 20 percent of total kWhs billed to approximately 37 percent. For example, Sundays and holidays are proposed to include on-peak hours. However, based on Test Year coincident peak ("CP") data filed by the Cooperative (Schedule I-8.0 and Rebuttal Exhibit DH-20), Staff concludes that: (1) SSVEC's CP was not coincident with Arizona Electric Power Cooperative, Inc.'s ("AEPCO") CP during the Test Year, (2) SSVEC's CP never occurred on a Sunday during the Test Year, and (3) AEPCO's CP never occurred on a Sunday during the year 2008. These findings are significant because since January, 2008 SSVEC continues to receive power from AEPCO, but as a partial requirements member. In addition, neither SSVEC or AEPCO incurred respective system peaks on Sundays during the Test Year. Consequently, Staff concludes that it would be inappropriate for SSVEC to include on-peak hours on Sundays. Furthermore, Staff is concerned that SSVEC's residential TOU rates have attracted less than 20 Test Year customers from a residential base consisting of more than 40,000 customers. Staff applauds SSVEC for the accomplishments it has achieved in offering TOU rate options to its members. However, Staff believes that residential TOU rates that would include on-peak Sunday usage could discourage existing or prospective residential customers from participating in TOU programs.

Q. Recognizing that Staff separately recommended approval of its proposed customer charges as filed, what are Staff's additional recommendations regarding its proposed rate design for residential TOU customers?

A. Supported by the discussions above, Staff recommends that its proposed residential TOU revised on-peak rate, off-peak rate and TOU sales volumes be approved. In addition, Staff recommends that the Commission not approve SSVEC's request to include residential TOU on-peak Sunday hours.

SERVICE CHARGE FEES

Q. Does staff agree with SSVEC's findings and recommendations regarding their proposed service fees?

A. No. Mr. Hedrick has incorrectly concluded that $904,772 is the amount of increases proposed by SSVEC for service fees. The figure quoted by Mr. Hedrick is actually the increase to the "Other Revenue" category as proposed by SSVEC on Schedule N-1.0. The other revenue category includes service charge fee revenues as adjusted by SSVEC in the amount of $603,308, along with revenues from Fort Huachuca, leased electric plant and rent from electric properties (SSVEC's original filing, Schedule C-4.0). Using the numbers reported in Mr. Hedrick's Rebuttal testimony, it would appear that Staff only recommended average service fee charge increases of approximately 38 percent. This correction is important to note because Staff proposed service fee increases that overall amount to an increase of approximately 57 percent.

Q. Are there any other reasons why Staff disagrees with SSVEC's recommendation to accept the service fees proposed by SSVEC?

A. Yes. Staff has actual labor index data from July 1993 to January 2008 as published in the Handy-Whitman Bulletin ("HWB") for the Plateau Region that includes Arizona. The data indicate an increase in labor costs equal to 59.4 percent, over that period, since SSVEC's last rate case. All applicable service fees were increased at least 60 percent as summarized on page 2 of WHM-2 in Staff's Direct testimony.

Q. How does Staff resolve SSVEC's concern that the HWB only takes into consideration labor costs?

A. If one looks at Mr. Hedrick's Exhibit DH-21 filed with his Rebuttal testimony, it is clear that the only two expense categories underlying service fees are labor and transportation. Staff has properly addressed labor costs. Regarding transportation costs, the overwhelming majority (81 percent) of calls occur during normal hours. SSVEC has proposed a tariff change that allows SSVEC to collect mileage fees at the applicable IRS rate per mile. Currently that mileage rate is capped at $0.40 per mile. Staff did not oppose this proposed tariff change in order to help the Cooperative offset transportation-related expenses incurred while servicing its members.

Q. What are Staff's recommendations regarding its proposed service fee charges as they were designed in this Docket?

A. Supported by the discussions above, Staff recommends that its proposed service fee charges be approved as originally filed.

SUMMARY OF TESTIMONY AND RECOMMENDATIONS

Briefly summarize your Surrebuttal Testimony and recommendations.

1. Staff recommends approval of its customer charges as summarized on page 1 of WHM-2 in Staff's Direct testimony.
2. Staff recommends approval of its proposed residential TOU revised on-peak rate of $0.16572 per kWh (WHM Surrebuttal Attachment 1).

3. Staff recommends approval of its proposed residential TOU off-peak rate of $0.09841 per kWh.
4. Staff recommends approval of its proposed residential TOU sales volumes as shown on WHM-1, page 1 of Staff's Direct testimony.
5. Staff recommends that the Commission not approve SSVEC's proposal to include TOU on-peak Sunday hours.
6. Staff recommends approval of its proposed service fee charges as summarized on page 2 of WHM-2 in Staff's Direct testimony.

Q. Does this conclude your Surrebuttal testimony?

A. Yes.

Rate Design
(Docket NoE-01575A-08-0328)

17 Residential - TOU	Present Rates	Staff Proposed	Present Revenues	Proposed Revenues	$ Delta	% Delta
Monthly Customer Charge	$11.40	$13.25	$2,371	$2,756	$385	16.23%
Cost Per KWh: On-Peak	$0.14050	$0.16572				
Cost Per KWh: Off-Peak	$0.07319	$0.09841				
Total Kwh Used: On-Peak	43,805	43,805	$6,155	$7,259	$1,105	17.95%
Total Kwh Used: Off-Peak	166,197	166,197	$12,164	$16,356	$4,192	34.46%
Kwhs in Minimun:	0	0	0	0		
Total Billings:	208	208				
Subtotal (kWh and $)	210,002	210,002	$20,690	$26,371	$5,681	27.46%
WPCA			$2,797	$0	($2,797)	-100%
Total Revenue			$23,487	$26,371	$2,884	12.28%

EXHIBIT
ALL-STATE LEGAL®
S-10
admitted

BEFORE THE ARIZONA CORPORATION COMMISSION

KRISTIN K. MAYES
Chairman
GARY PIERCE
Commissioner
PAUL NEWMAN
Commissioner
SANDRA D. KENNEDY
Commissioner
BOB STUMP
Commissioner

IN THE MATTER OF THE APPLICATION OF SULPHUR SPRINGS VALLEY ELECTRIC COOPERATIVE, INC. FOR A HEARING TO DETERMINE THE FAIR VALUE OF ITS PROPERTY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RETURN THEREON, TO APPROVE RATES DESIGNED TO DEVELOP SUCH RETURN AND FOR RELATED APPROVALS.	DOCKET NO. E-01575A-08-0328

DIRECT

TESTIMONY

OF

STEVE IRVINE

PUBLIC UTILITIES ANALYST IV

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

JANUARY 26, 2009

TABLE OF CONTENTS

EXHIBITS

EXECUTIVE SUMMARY
SULPHUR SPRINGS VALLEY ELECTRIC COOPERATIVE, INC.
DOCKET NO. E-01575A-08-0328

This testimony addresses Sulphur Springs Valley Electric Cooperative, Inc.'s ("SSVEC") Demand-side Management ("DSM") program cost recovery and Renewable Energy Standard and Tariff ("REST") program cost recovery.

Staff recommends that SSVEC file with Docket Control a revised version of the DSM program description having removed references to the Time of Use ("TOU") rates and controlled rate program for irrigators, and having made other conforming changes, when filing an application for approval of new DSM programs.

Staff recommends that costs prudently incurred in connection with Commission-approved DSM activities be recovered entirely through a DSM adjustment tariff.

Staff recommends that Commission-approved DSM costs should be assessed to all SSVEC electric customers as a clearly labeled single line item per kWh charge on customer bills.

Staff recommends, should the Commission approve SSVEC's recommendation to include some part of DSM program expense recovery in base rates, that the Commission also clarify that a negative DSM adjustor may be used to lower DSM program expense recovery below the rate included in base rates.

Staff recommends that SSVEC continue to report on DSM program expenses semi-annually as it does presently, except with revisions as discussed herein.

Staff recommends that SSVEC file the DSM program expense reports in Docket Control and that SSVEC redact any personal information such as the names and addresses associated with customers participating in DSM programs.

Staff recommends that SSVEC's DSM program expense reports include the following: (i) the number of measures installed/homes built/participation levels; (ii) copies of marketing materials; (iii) costs incurred during the reporting period disaggregated by type of cost, such as administrative costs, rebates, and monitoring costs; (iv) gas and electric savings as determined by the monitoring and evaluation process; (v) estimated environmental savings; (vi) the total amount of the program budget spent during the previous six months and, in the end of year report, during the calendar year; (ix) the amount spent since the inception of the program; (vii) any significant impacts on program cost-effectiveness; (ix) descriptions of any problems and proposed solutions, including movements of funding from one program to another; (x) any major changes, including termination of the program.

Staff recommends that SSVEC submit to the Commission, through Docket Control a filing, by April 1st of each year, that includes its proposed new DSM adjustor rate. Staff further recommends that the filing be considered and adjudicated by the Commission in Open Meeting.

Staff recommends that SSVEC's DSM adjustor rate be reset annually on June 1st of each year. Staff further recommends that the per kWh rate be based upon currently projected DSM costs for that year (the year for which the calculation is being made), adjusted by the previous year's over- or under-collection, divided by projected retail sales (kWh) for that same year.

Staff recommends that SSVEC's annually proposed new DSM adjustor rate become effective on June 1st after approval by the Commission.

Staff recommends that SSVEC submit proposed programs to the Commission for approval.

Staff recommends that SSVEC file an application requesting approval of the new DSM programs proposed by SSVEC in this application.

Staff recommends that the initial DSM adjustor rate be set to recover prudently incurred DSM costs associated only with approved programs presently in place.

Staff recommends that the initial adjustor rate be set at $0.000256 per kWh until the annual reset of the adjustor rate.

Staff recommends that prudently incurred costs associated with approved DSM programs that have been factored into the Wholesale Power Cost Adjustor ("WPCA") account balance remain in the WPCA account balance.

Staff recommends that the Commission authorize an adjustor mechanism for SSVEC to replace the REST Surcharge.

Staff recommends that SSVEC file with the Commission, within 30 days of the date of the decision in this case, a REST tariff with conforming changes to reflect recovery through the adjustor rather than through the surcharge used presently.

INTRODUCTION

Q. Please state your name, occupation, and business address.

A. My name is Steve Irvine. I am a Public Utilities Analyst IV employed by the Arizona Corporation Commission ("ACC" or "Commission") in the Utilities Division ("Staff"). My business address is 1200 West Washington Street, Phoenix, Arizona 85007.

Q. Briefly describe your responsibilities as a Public Utilities Analyst.

A. In my capacity as a Public Utilities Analyst, I conduct studies to estimate the cost of capital component and determine the overall revenue requirement in rate proceedings. I also design rates to generate the revenue requirement in rate proceedings. My duties have also included evaluating a variety of applications or components of applications including Demand-side Management ("DSM") programs and Renewable Energy Standard and Tariff ("REST") programs.

Q. Please describe your educational background and professional experience.

A. In 1994, I graduated from Arizona State University, receiving a Bachelor of Science degree in Business Marketing. In 1997, I received a Masters degree in Public Administration from Arizona State University. I began employment with the Commission in May of 2001 and have worked in the Utilities Division since September of 2002.

Q. What is the scope of your testimony in this case?

A. My testimony provides Staff's recommendations regarding Sulphur Springs Valley Electric Cooperative, Inc.'s ("SSVEC" or "Company") DSM program and REST program.

Q. Have you reviewed the testimony submitted by the Company in this case?

A. Yes. I reviewed Company witness Mr. Jack Blair's testimony which addresses SSVEC's DSM proposals.

Q. Briefly summarize how your testimony is organized.

A. My testimony is organized into four sections. Section one is this Introduction section. Section two discusses DSM program Cost Recovery. Section three discusses Renewables Programs Cost Recovery. Section four is a Summary of Staff Recommendations.

Q. Mr. Blair's testimony mentions Time of Use ("TOU") rates and a controlled rate program for irrigators. Are these DSM?

A. No. TOU rates and the controlled rate program for irrigators both manage load, but these subjects are typically addressed by the Commission as a rate component dealt with in rate design rather than as a component of DSM. These matters will be addressed in the rate design testimony of Staff witness William Musgrove. Mr. Musgrove will not address their merits as their merits are not in dispute in this case.

Q. Does Staff have a recommendation in regard to the TOU rates and the controlled rate program for irrigators as they related to SSVEC's DSM proposals?

A. Yes. Attachment A to the pre-filed Direct written testimony of SSVEC witness Mr. Jack Blair is a description of SSVEC's DSM program titled "Sulphur Springs Valley Electric Cooperative Inc.'s Demand-side Management Program." The program description includes references to TOU rates and the controlled rate program for irrigators. Staff recommends that SSVEC file with Docket Control a revised version of the DSM program description having removed references to the TOU rates and controlled rate program for irrigators, and having made other conforming changes when filing an application for approval of new DSM programs.

DSM PROGRAM COST RECOVERY

Q. What is DSM?

A. DSM is the planning, implementation, and evaluation of programs to shift peak load to off-peak hours, to reduce peak demand (kW), and to reduce energy consumption (kWh) in a cost-effective manner.

Q. What DSM programs does SSVEC currently have?

A. Presently SSVEC has the following DSM programs: Touchstone Energy® Efficient Home Program, Energy Efficient Heat Pump Rebate Program, Energy Efficient Improvement Loan Program, and Commercial and Industrial Energy Management Program.

Q. What new DSM programs does SSVEC propose?

A. SSVEC proposes the Energy Efficient New Home or Remodel Rebate program, Energy Efficient Water Heater Rebates program, and Commercial and Industrial Energy Efficiency Improvement Loan Program.

Q. Is there presently a funding mechanism in place through which SSVEC recovers its prudently incurred costs for DSM programs?

A. Yes. There is currently a provision for SSVEC to include pre-approved DSM costs in its Wholesale Power Cost Adjustor ("WPCA") mechanism to allow recovery of DSM costs in the WPCA component of customers' bills.

Q. Is the practice of recovering DSM costs through the WPCA the best method of DSM cost recovery?

A. No. DSM costs are not purchased power costs and, therefore, the WPCA is not the best mechanism for recovery of DSM costs. To include such costs within the WPCA could cause confusion about the cost of DSM. Another disadvantage of this type of recovery mechanism is that, if SSVEC's service territory were opened for retail competition, customers who choose to obtain power in the competitive market would not pay for DSM which is a public benefit.

Q. What method does SSVEC propose for recovery of DSM program costs?

A. On page 17 of the pre-filed written direct testimony of SSVEC witness Jack Blair, SSVEC proposes that $485,000 of DSM be included in base rates as a component of customers' energy charge. The Company states that this amount is based on SSVEC's known and measurable DSM expenses included in the 2007 rate case test year. SSVEC further proposes that any DSM expenses above that amount be recovered through a proposed DSM Adjustment Tariff.

Q. Does SSVEC currently have a DSM Adjustment Tariff?

A. No. DSM costs are presently collected through the WPCA.

Q. Does SSVEC currently collect any DSM costs through base rates?

A. No.

Q. Has SSVEC included a sample of a proposed DSM Adjustment tariff in the application?

A. The application makes several references to a DSM Adjustment contained in Tariff Sheet No. 45; however, Staff can locate neither a proposed Tariff Sheet No. 45 nor a DSM Adjustment Tariff in the application.

Q. Does Staff support SSVEC's proposal for recovery of DSM program costs through a combination of base rates and a DSM adjustment tariff?

A. No. Recovery of DSM program costs through a combination of base rates and a DSM adjustor mechanism could lead to disorder and a lack of transparency in rates?

Q. How might recovery of DSM program costs through a combination of base rates and a DSM adjustor mechanism lead to disorder and a lack of transparency in rates?

A. Inclusion of DSM program costs in base rates combines a portion of DSM costs with other costs typically included in base rates. This has the effect of making base rates the sum of approved recoverable costs of provision of service plus a portion of DSM program costs. Dispersion of DSM program costs through multiple rate components has the effect of making DSM program costs less transparent and less identifiable because the total of DSM program costs in such a scenario would be the sum of the portion of DSM program costs recovered through base rates plus the portion of DSM program costs recovered through the DSM adjustor mechanism.

Q. Is there a rate design format that is more orderly and provides greater cost transparency?

A. Yes. Recovery of all of the DSM program costs through a DSM adjustor mechanism is both more orderly and provides greater cost transparency.

Q. How is a DSM adjuster mechanism more orderly and transparent?

A. When DSM program costs are contained solely in the DSM adjustor mechanism, there is no mixing of DSM costs with other costs. The rate charged to customers for DSM program costs can be readily identified by customers by simply referring to the DSM adjustor rate. The rate charged for DSM program costs could be even more transparent to customers if included as a line item on their bills. Consider the following hypothetical example illustrated in Table I. Imagine in this scenario that the Commission authorizes recovery of approved costs of provision of service at a rate of $5.00 per kWh. Also imagine that the Commission authorizes collection of DSM program costs at $2.00 per kWh. Should SSVEC's proposal be adopted, base rates would be $7 per kWh and the DSM adjustor rate would be $0.00 as seen in the row marked Scenario I. Should Staff's recommendation be adopted, base rates would be $5.00 per KWh and the DSM adjustor Rate would be $2.00 as seen in Scenario II. Please recall that these rates are hypothetical and used for this example because they are plain, round, and illustrative rather than representative of actual costs or rates. Please also note that this example excludes other billing components included in actual bills for purposes of simplicity.

Table I

	Base Rates	DSM Adjustor Rate	Total Rate
Scenario I SSVEC proposal: Mix DSM costs in base rates and DSM adjustor – with no DSM cost recovery in adjustor initially.	$7.00 ($2.00 of DSM costs embedded in base rates)	$0.00	$7.00
Scenario II Staff proposal: Recover DSM costs only through a DSM adjustor rate	$5.00	$2.00	$7.00

In Scenario I of Table I, customers may mistakenly conclude that no recovery for DSM program costs is occurring as the DSM adjustor rate is $0.00. In Scenario II of Table I, customers are likely to conclude that the recovery for DSM program costs is $2.00 per kWh, which is the actual DSM program cost recovery rate in this example.

Now consider what would occur in this example should subsequent to a rate case approving these rates that SSVEC secure approval to increase recovery DSM program costs by $1.00 per kWh. This change is illustrated in Table II.

Table II

	Base Rates	DSM Adjustor Rate	Total Rate
Scenario III SSVEC proposal: Mix DSM costs in base rates and DSM adjustor	$7.00 ($2.00 of DSM costs embedded in base rates)	$1.00	$8.00
Scenario IV Staff proposal: Recover DSM costs only through a DSM adjustor rate	$5.00	$3.00	$8.00

In Scenario III of Table II, customers may mistakenly conclude that recovery for DSM program costs is occurring at a rate of $1.00 per kWh. In Scenario IV of Table II, customers are likely to conclude that the recovery for DSM program costs is $3.00 per kWh, which is the actual DSM program cost recovery rate in this example.

Finally, consider what would occur should the Commission determine at a future time that recovery of DSM program costs should be reduced to a rate of $1.00 per kWh in this hypothetical example. The change is illustrated in Table III.

Table III

	Base Rates	DSM Adjustor Rate	Total Rate
Scenario V SSVEC proposal: Mix DSM costs in base rates and DSM adjustor	$7.00 ($2.00 of DSM costs embedded in base rates)	$-1.00	$6.00
Scenario VI Staff proposal: Recover DSM costs only through a DSM adjustor rate	$5.00	$1.00	$6.00

In Scenario V of Table III, customers may be confused by the negative DSM adjustor rate. In Scenario VI of Table III, customers are likely to conclude that the recovery for DSM program costs is $1.00 per kWh, which is the actual DSM program cost recovery rate in this example.

Q. What method does Staff propose for recovery of DSM program costs?

A. Staff recommends that costs prudently incurred in connection with Commission-approved DSM activities be recovered entirely through a DSM adjustment tariff. Staff makes this recommendation in order to achieve more cost transparency and order in SSVEC's rates.

Q. How should DSM costs be charged to SSVEC customers?

A. Staff recommends that Commission-approved DSM costs should be assessed to all SSVEC electric customers as a clearly labeled single line item per kWh charge on customer bills. The per kWh charge would be a result of the DSM adjustor mechanism calculation and would be re-calculated annually. Staff believes an individual DSM line-item charge would provide maximum transparency to SSVEC customers. In addition, customers who obtain power in the competitive market would continue to pay the charge.

Q. Would recovery of DSM program costs wholly through an adjustor necessarily cause a reduction in recovery of expenses?

A. No. As seen in the Total Rate column of each of the tables, the same total rate is collected whether the DSM program costs are recovered either wholly or in part through the adjustor.

Q. Would inclusion of some portion of DSM program costs in base rates help to ensure that SSVEC will recover at least that portion of DSM program costs?

A. No. As seen in Table III use of a negative adjustor rate can reduce collection of DSM program costs below the level included in base rates.

Q. Could there ever be circumstances when it was desirable to make use of a negative adjustor?

A. Yes. Many of the programs are dependent on customer participation. Should customers choose to not participate in incentive or loan programs it is possible that DSM program expenses may fall below the amounts proposed by SSVEC for inclusion in base rates. Should the Commission elect to approve SSVEC's recommendation to include a portion of DSM program cost recovery in base rates, and should expenses fall below the level included in base rates, it may be appropriate to also scale down the DSM program cost recovery by making use of a negative adjustor rate. Staff does not, however, recommend that SSVEC's proposal to include DSM program cost recovery in base rates be approved.

Q. Are there other circumstances where use of a negative adjustor is appropriate?

A. Yes. Should the Commission choose to eliminate or scale back SSVEC's DSM programs it may also be appropriate to also reduce DSM program cost recovery. Other circumstances not yet contemplated by Staff, the Commission, or SSVEC could develop in the future and necessitate a reduction to the DSM program cost recovery rate.

Q. Can the Commission make use of a negative adjustor rate in order to reduce DSM program cost recovery below the level included in base rates?

A. It is mathematically possible and there is no ratemaking imperative that precludes this. Staff would point out that some dispute about this matter could arise should SSVEC's proposal for the operation of the adjustor be approved by the Commission. SSVEC's proposal for the operation of the adjustor only mentions use of the adjustor in the context of recovery of costs above the amount contained in base rates. SSVEC's proposal does not mention use of the adjustor for the purpose of lowering total DSM program expense recovery below the level contained in base rates.

Q. What recommendation does Staff have that addresses a lack of clarity in regard to the matter of whether the Commission could make use of a negative adjustor rate?

A. Staff recommends that, should the Commission approve SSVEC's recommendation to include some part of DSM program expense recovery in base rates, that the Commission should also clarify that a negative DSM adjustor rate may be used to lower DSM program expense recovery below the rate included in base rates. Staff makes this recommendation in order to allow the Commission the flexibility to scale the operation of DSM program expense recovery to whatever level is necessary based on future circumstances. This recommendation is contingent on the Commission approving SSVEC's proposed inclusion of DSM program expense recovery in base rates. Staff does not recommend, however, that SSVEC's proposal be approved.

Q. Does Staff anticipate that it will be necessary to reduce DSM program expense recovery below the level approved by the Commission in this case?

A. No. Staff's only interest in this matter is to preserve for the Commission the flexibility to scale DSM cost recovery to levels the Commission determines is appropriate. Staff does not believe that a future reduction to the rate of DSM cost recovery will be necessary.

Q. Has the Commission ever ordered that expenses for a particular program be recovered entirely through an adjustor rate rather than through a combination of base rates and an adjustor mechanism?

A. Yes. In Decision No. 58358 the Commission did so for SSVEC's Conservation Program Account. This Decision establishes SSVEC's present DSM program expense recovery methodology. The Decision approved Staff's recommendation, which was as follows:

> Staff has proposed the elimination of the expenses of a number of SSVEC's programs from base rates and their inclusion instead in a Conservation Program Account to allow SSVEC to recover costs of programs pre-approved by Staff as the level of expenses and the programs change. The account would be added to the purchased power and fuel adjustor account and recovered as part of the purchased power adjustor. Conservation program costs would be kept and accounted for separately and SSVEC would allocate this account only those costs not recovered by AEPCO in its conservation account.[1]

This Decision is similar to Staff's recommendation in this case, in that both cause recovery of program costs to be made entirely through an adjustor mechanism rather than parceling costs between base rates and an adjustor mechanism.

[1] Decision No. 58358, July 1993. Page 31 lines 15 – 23.

Q. Why did Staff's recommendation, adopted in Decision No. 58358, prescribe recovery of program expenses as a component of the purchased power adjustor rather than through a separate adjustor dedicated specifically for that program?

A. It is likely that Staff did not contemplate the use of a variety of separate adjustors as it was not commonplace at the time. Since that time it has become customary to make use of a variety of separate adjustors for the recovery of certain distinct costs.

Q. Does Staff have any concerns with the procedure SSVEC proposes to be used for reporting on DSM program expenses and making changes to the DSM adjustor rate?

A. Yes. SSVEC's proposal is as follows:

> On or before October 1st of each year, SSVEC shall file with the Commission Staff a DSM Program Report that details all DSM Program expenses above the Base Amount for which SSVEC is seeking recovery through the DSM Adjustment Tariff. On or before December 1st of each year, Staff shall issue its approval of the expenses for which SSVEC is authorized to recover. If Staff does not respond to the DSM Program Report filing by December 1st, the expenses shall be deemed approved. SSVEC will then set/reset the DSM Adjustor as of January 1st of each year.

Since Staff does not recommend inclusion of DSM program expenses in base rates, Staff cannot support the SSVEC proposal. Furthermore, Staff has other concerns with the proposal.

Q. Please describe these other concerns?

A. It is unclear to Staff what information SSVEC proposes to report. SSVEC offers no further explanation about what information would be reported. Second, SSVEC's proposal appears to envision a method where it would detail "all DSM Program expenses above the Base Amount for which SSVEC is seeking recovery through the DSM

Adjustment Tariff." SSVEC offers no further explanation about how it would determine which program expenses were "above the Base Amount" and therefore detailed, and which program expenses are not "above the Base Amount" and therefore not detailed. It is difficult for Staff to contemplate a productive reason to designate any program expense as either above or below the Base Amount. One interpretation of SSVEC's proposal is that it intends only to report on the extent to which total program expenses exceed the Base Amount. Should this be SSVEC's intention, the Commission will be provided with only cursory information related to program expenses. Another interpretation is that SSVEC intends to associate particular incurred expenses with being "above the Base Amount", others as not being "above the Base Amount", and then provide information describing the activities it associates with being "above the Base Amount." Staff's concern with this interpretation is that money is fungible and any construct that assigns an incurred expense either above or below the Base Amount is subjective. More importantly, every incurred expense should be scrutinized to verify that it is an appropriate cost that should be recovered from ratepayers.

Q. How does SSVEC report on DSM program expenses presently?

A. SSVEC submits a semi-annual report that lists each DSM expense. The report includes supporting information including examples of published materials, invoices for costs, and for some programs rosters of individuals or addresses that received services.

Q. What is Staff's recommendation with regard to reporting on DSM program expenses?

A. Staff recommends that SSVEC continue to report on DSM program expenses semi-annually as it does presently. Other utilities report on DSM programs on a semi-annual basis and if SSVEC were to report annually the method would be inconsistent with other utilities' practices. Staff recommends that SSVEC file the DSM program expense reports in Docket Control in order to make the reports more widely accessible. Staff recommends that SSVEC redact any personal information such as the names and addresses associated with customers participating in DSM programs in order to not make personal information public record. In order to make the reports more informative and to make the reporting requirements more similar to those of other utilities, Staff recommends that SSVEC's DSM program expense reports include the following: (i) the number of measures installed/homes built/participation levels; (ii) copies of marketing materials; (iii) costs incurred during the reporting period disaggregated by type of cost, such as administrative costs, rebates, and monitoring costs; (iv) gas and electric savings as determined by the monitoring and evaluation process; (v) estimated environmental savings; (vi) the total amount of the program budget spent during the previous six months and, in the end of year report, during the calendar year; (ix) the amount spent since the inception of the program; (vii) any significant impacts on program cost-effectiveness; (ix) descriptions of any problems and proposed solutions, including movements of funding from one program to another; (x) any major changes, including termination of the program.

Q. What proposal does SSVEC have for authorization for changes to the DSM adjustor?

A. SSVEC proposes that it provide to Staff its DSM program Report by October 1st annually and by December 1st Staff shall issue its approval of the expenses. SSVEC would then set/reset the DSM adjustor as of January 1st of each year.

Q. What procedure should be used to reset the per kWh DSM adjustor rate?

A. Staff recommends SSVEC submit to the Commission through Docket Control a filing by April 1st of each year that includes its proposed new DSM adjustor rate. This timeline will allow a complete calendar year of DSM costs to develop before resetting the adjustor. Staff recommends that the filing be considered and adjudicated by the Commission in Open Meeting. Adjudication of the filing by the Commission, rather than by Staff, will allow the Commission to directly manage recovery of the DSM rate and the impact it has on ratepayers.

Staff recommends that SSVEC's DSM adjustor rate be reset annually on June 1st of each year and that the per kWh rate be based upon currently projected DSM costs for that year (the year for which the calculation is being made), adjusted by the previous year's over- or under-collection, divided by projected retail sales (kWh) for that same year. Other consideration can be given for extenuating circumstances such as gradualism in change of the rate. This process will scale DSM cost recovery to the actual DSM costs, with any prudent adjustment being made by the Commission.

The filing should include information detailing SSVEC's DSM expenses, prudently incurred during the previous calendar year in connection with Commission-approved DSM programs and activities, and its actual DSM cost recovery collected in the previous year. The disaggregated costs placed in each DSM adjustor sub-account for the previous year should be summed to a total DSM cost and compared with documented DSM cost recovery that same year to determine the over- or under-collection adjustment needed to modify projected DSM costs for the current year adjustor rate calculation. This information will support the calculation of the proposed adjustor rate.

Staff also recommends that SSVEC's annually proposed new DSM adjustor rate become effective on June 1st after approval by the Commission. This will provide a mechanism for SSVEC to adjust the adjustor rate in the event that the Commission is unable to address the matter in a timely fashion.

Q. What procedure would SSVEC follow in order to implement new DSM programs should it decide to do so or be required to do so?

A. Staff recommends that SSVEC submit proposed programs to the Commission for approval. This will allow the Commission to actively manage what programs are included in SSVEC's DSM efforts. After a program is approved, SSVEC may begin entering costs for that program, as they are incurred, into the DSM adjustor mechanism account.

Q. Is Staff recommending that SSVEC file an application for approval of the new DSM programs proposed by SSVEC at this time?

A. Yes. Staff recommends that SSVEC file an application requesting approval of the new DSM programs proposed by SSVEC in this application. This will allow an opportunity for gathering of information and consideration of the new programs in greater detail. The application includes some information about new programs proposed by SSVEC, but further information should be gathered in order to provide a basis for a fully informed decision. SSVEC proposes in the application a list of the information that should be detailed with each application for a new program. The list includes the following:

- Description of the program
- Purpose of the program
- Expected level of participation
- Expected kW and/or kWh savings
- Expected societal costs
- Plans for implementation, scheduling, monitoring and evaluation
- Anticipated advertising and marketing expenses

- Any customer rebates or other incentives

While the application provides much of this information, it does not address each of these matters for each newly proposed program. A more expansive and detailed explanation of the programs and expected savings would also be beneficial for the Commission's consideration of the new programs. For example, the Energy Efficient Water Heater Rebates program is characterized as offering a $150 one-time rebate for the installation of a replacement electric water heater. The application does not state whether SSVEC would or would not offer the rebate to customers replacing a gas water heater with an electric water heater. Such information is necessary so that the effects of fuel-switching can be considered when evaluating the proposed programs. More detailed information, such as this, is necessary in order for the Commission to make a more fully informed decision in regard to the new programs.

Q. In the past has Staff recommended that newly proposed DSM programs be evaluated in a separate docket following a rate case?

A. Yes. Staff made a similar recommendation in a rate case for Tucson Electric Power Company (Decision No. 70628 of December 2008). The Commission approved this recommendation. There are other examples where the Commission has considered changes to existing DSM rate recovery mechanisms within a rate case, but considered proposals for new DSM programs outside the rate case.

Q. What level of recovery does SSVEC propose for DSM costs?

A. As mentioned previously, SSVEC proposes that $485,000 of DSM expense be included in base rates as a component of customers' energy charge. While SSVEC proposes that DSM costs in excess of $485,000 be collected through the proposed DSM adjustor, Staff finds no mention in the application of a proposal by SSVEC to set the DSM adjustor rate at a specific level. On page 17 of the pre-filed direct written testimony of SSVEC witness Jack Blair, SSVEC proposes that the total dollar amount of annual DSM spending be approximately $729,500. SSVEC proposes recovery of the difference between the total annual DSM spending ($729,500) and the amount SSVEC proposed for inclusion in base rates ($485,000) through the DSM adjustor, but does not clearly describe when it proposes that the adjustor be set for recovery of that difference. SSVEC may envision that the Commission would authorize a particular DSM adjustor rate for recovery of expenses above $485,000 during the rate case, or at some later date such as at the time of SSVEC's proposed annual filing for an adjustor change.

Q. **What DSM costs does Staff recommend be collected through the DSM adjustor until such time as the newly proposed programs can be evaluated for approval and recovery through the DSM adjustor?**

A. As Staff recommends that SSVEC's proposed DSM programs be considered following a separate application for consideration of the new programs, Staff recommends that the initial DSM adjustor rate be set to recover prudently incurred DSM costs associated only with approved programs presently in place.

Q. **How did Staff determine the level of costs associated with approved DSM programs presently in place?**

A. Staff asked SSVEC in a data request to detail the level of DSM expenses it included in its proposed operating expenses. The response included a schedule of test year DSM expenses. The schedule indicated that in 2007, $204,396.17 in DSM expense was reported to the Commission. The response also included $280,600.00 expense for a line item called 'All Electric Home Rebates' that was not reported to the Commission. The portion of the data response that addresses this question is included as exhibit SPI-1. Costs associated with this program were not yet reported to the Commission as they were incurred for a program that has not yet been approved. As this program is not yet approved, Staff does not recommend that they be included for recovery at this time.

Q. How did Staff use this information in calculation of Staff's proposed DSM adjustor rate?

A. Staff divided $204,396.17 by the quantity of kWh's used in Staff's rate design to determine the rate that should be charged per kWh for recovery of presently approved program expense. The formula is as follows:

(100 percent of annual budget for presently approved programs / Staff's kWh quantity)

$204,396.17 / 799,860,156 kWh's = $0.000256 per kWh.

Q. What consideration does Staff give to recovery of previously incurred DSM costs?

A. SSVEC has dealt with recovery of previously incurred DSM costs by adding them to the balance of their WPCA account. The current WPCA account balance reflects a portion of historically incurred DSM costs. Staff recommends that prudently incurred costs associated with approved DSM programs that have been factored into the WPCA account balance remain in the WPCA account balance to facilitate recovery of those costs. This process is necessary because it would be a difficult and subjective process to determine what part of the present WPCA account balance is attributable to DSM costs. In time, any remaining DSM cost embedded in the WPCA account balance will be recovered at some future time when the WPCA account balance reduces to $0.00.

Q. Why does Staff not recommend recovery of costs associated with proposed programs at this time?

A. Staff finds that there is some lack of clarity regarding the proposed DSM programs and their budgets. Staff concludes that recovery of costs associated with proposed DSM programs should be deferred until they are approved in a subsequent application and the DSM adjustor be reset at the time of the next annual reset of the adjustor. Staff asked SSVEC in a data request to provide a budget for each of the DSM programs. The response is included as Exhibit SPI-2. The response details through line items budget amounts for each program. Collectively they total $729,500 which is the total annual DSM program budget cited in the application. Staff notes that the $280,600.00 expense for the line item called 'All Electric Home Rebates', that SSVEC proposes for inclusion as an operating expense and recovered in base rates, does not appear to correspond to a particular program title in the list of programs seen in Exhibit SPI-2. The $286,600.00 expense also does not seem to correspond with any program budget or combination of program budgets seen in Exhibit SPI-2. Furthermore, the program's title 'All Electric Home Rebates' appears, at face value, to promote the use electric appliances to the exclusion of gas appliances. Programs that promote the use of electric appliances as a replacement to gas appliances may create competition between gas utilities and electric utilities and consequently inefficiency.

Q. What initial adjustor rate does Staff recommend?

A. Staff recommends that the adjustor rate be set at $0.000256 per kWh until the annual reset of the adjustor rate.

Q. What is the bill impact of Staff's proposed adjustor rate?

A. For a residential customer on the tariff Residential Service – Schedule R using 728 kWh per month (average usage), the initial DSM adjustor rate would result in a monthly charge of $0.19 or $2.24 per year. A small commercial customer on the tariff General Service – Schedule GS using 483 kWh (average usage) in a month would pay a monthly charge of $0.12 or $1.49 per year.

RENEWABLES PROGRAM COST RECOVERY

Q. Why is Staff introducing the issue of cost recovery for renewables programs in this testimony?

A. SSVEC is subject to the REST rules contained in A.A.C. R14-2-1801 through A.A.C. R14-2-1816. These rules require SSVEC to obtain renewable energy through production or procurement. These rules require SSVEC to produce or procure a progressively larger amount of renewable energy each year until 2024. The rules direct utilities to file tariffs for the recovery of costs associated with meeting the requirements of these rules. A.A.C. R14-2-1808 (D) states "If an Affected Utility has an adjustor mechanism for the recovery of costs related to Annual Renewable Energy Requirements, the Affected Utility may file a request to reset its adjustor mechanism in lieu of a Tariff pursuant to subsection (A)." A.A.C. R14-2-1808 (D) also states "The Affected Utility's filing shall provide all the information required by subsection (B), except that it may omit information specifically related to the fair value determination." An adjustor mechanism for recovery of the costs associated with the REST would provide a more efficient means for SSVEC to annually update the rate of recovery of its REST costs rather than annually filing a new tariff and proposing a fair value finding.

Q. Does SSVEC currently have a REST adjustor?

A. No. SSVEC recovers REST costs through a REST tariff and surcharge?

Q. How would the adjustor mechanism work?

A. SSVEC would include in each annual REST Implementation Plan application a request to change its renewable adjustor rate and caps, should a change to the adjustor or caps be necessary. Each requested change to the adjustor would be reviewed by Staff. Staff would then make recommendations to the Commission. The Commission could then approve, disapprove, or modify SSVEC's requested change to the adjustor rate in an Open Meeting as a component of the Commission's consideration of each annually proposed REST Implementation Plan.

Q. If approved, how would the REST adjustor be assessed to customers?

A. An "ACC Environmental Surcharge (REST)" line item currently appears in customer bills. The REST adjustor, as approved by the Commission, would take the place of this surcharge.

Q. What is Staff's recommendation in regard to a REST adjustor?

A. Staff recommends that the Commission authorize an adjustor mechanism for SSVEC to replace the REST Surcharge in order to facilitate a more efficient process for making changes to SSVEC's REST cost recovery. Staff further recommends that SSVEC file with the Commission a REST tariff with conforming changes within 30 days of the date of the decision in this case to reflect recovery through the adjustor rather than through the surcharge used presently.

SUMMARY OF STAFF RECOMMENDATIONS

Q. Please provide a summary list of Staff's recommendations.

- Staff recommends that SSVEC file with Docket Control a revised version of the DSM program description having removed references to the TOU rates and controlled rate program for irrigators, and having made other conforming changes when filing an application for approval of new DSM programs.
- Staff recommends that costs prudently incurred in connection with Commission-approved DSM activities be recovered entirely through a DSM Adjustment Tariff.
- Staff recommends that Commission-approved DSM costs should be assessed to all SSVEC electric customers as a clearly labeled single line item per kWh charge on customer bills.
- Staff recommends that should the Commission approve SSVEC's recommendation to include some part of DSM program expense recovery in base rates, that the Commission also clarify that a negative DSM adjustor may be used to lower DSM program expense recovery below the rate included in base rates.
- Staff recommends that SSVEC continue to report on DSM program expenses semi-annually as it does presently.
- Staff recommends that SSVEC file the DSM program expense reports in Docket Control and that SSVEC redact any personal information such as the names and addresses associated with customers participating in DSM programs.
- Staff recommends that SSVEC's DSM program expense reports include the following: (i) the number of measures installed/homes built/participation levels; (ii) copies of marketing materials; (iii) estimated cost savings to participants; (iv) gas and electric savings as determined by the monitoring and evaluation process; (v) estimated environmental savings; (vi) the total amount of the program budget spent during the previous six months and, in the end of year report, during the calendar year; (ix) the

amount spent since the inception of the program; (vii) any significant impacts on program cost-effectiveness; (ix) descriptions of any problems and proposed solutions, including movements of funding from one program to another; (x) any major changes, including termination of the program. Staff recommends that SSVEC submit a filing to the Commission through Docket Control by April 1st of each year that includes its proposed new DSM adjustor rate. Staff further recommends that the filing be considered and adjudicated by the Commission in Open Meeting.

- Staff recommends that SSVEC's DSM adjustor rate be reset annually on June 1st of each year and that the per kWh rate be based upon currently projected DSM costs for that year (the year for which the calculation is being made), adjusted by the previous year's over- or under-collection, divided by projected retail sales (kWh) for that same year.
- Staff recommends that SSVEC's annually proposed new DSM adjustor rate become effective on June 1st after approval by the Commission.
- Staff recommends that SSVEC submit proposed programs to the Commission for approval.
- Staff recommends that SSVEC file an application requesting approval of the new DSM programs proposed by SSVEC in the this application.
- Staff recommends that the initial DSM adjustor rate be set to recover prudently incurred DSM costs associated only with approved programs presently in place.
- Staff recommends that prudently incurred costs associated with approved DSM programs that have been factored into the WPCA account balance remain in the WPCA account balance.
- Staff recommends that the adjustor rate be set at $0.000256 per kWh until the Annual reset of the adjustor rate.

- Staff recommends that the Commission authorize an adjustor mechanism for SSVEC to replace the REST Surcharge.
- Staff recommends that SSVEC file with the Commission a REST tariff with conforming changes within 30 days of the date of the decision in this case to reflect recovery through the adjustor rather than through the surcharge used presently.

Q. Does this conclude your direct testimony?

A. Yes, it does.

Exhibit I

Response to DSM 5.02
DSM Costs in 2007 Expenses

The following table outlines DSM expenses included in expenses. All electric home rebates are included although this cost is not approved for DSM through the ACC. The all electric home rebates were included in the DSM program in an earlier response to data.

Account	Description	Amount	Type
909.00	Production Costs for Co-op Connection	$ 228.16	Advertising Costs
909.10	Printing Costs for Co-op Connection	$ 8,633.87	Advertising Costs
909.10	Costs for Currents Magazine	$ 5,173.81	Advertising Costs
912.20	Rebates to existing homeowners	$ 94,800.00	Existing Home Rebates
912.40	Inspections on Touchstone Energy Homes	$ 6,857.20	New Home Rebates
912.40	Manpower Costs	$ 24,544.07	Manpower Costs
912.40	Newspaper Costs to Tyau Advertising	$ 5,143.49	Advertising Costs
912.40	Radio Advertising to Tyau Advertising	$ 4,582.35	Advertising Costs
912.40	TV Advertising to Tyau Advertising	$ 6,289.90	Advertising Costs
912.55	Newspaper Costs to Tyau Advertising	$ 6,522.54	Advertising Costs
912.55	Radio Advertising to Tyau Advertising	$ 3,839.18	Advertising Costs
912.55	TV Advertising to Tyau Advertising	$ 2,056.12	Advertising Costs
913.00	TV Advertising to Tyau Advertising	$ 2,871.05	Advertising Costs
921.00	Newspaper Costs to Tyau Advertising	$ 3,642.82	Advertising Costs
921.00	Radio Advertising to Tyau Advertising	$ 4,575.12	Advertising Costs
921.00	TV Advertising to Tyau Advertising	$ 21,813.99	Advertising Costs
	Variance with amounts reported to ACC	$ 2,822.50	
	2007 DSM Costs reported to the ACC	$ 204,396.17	
912.50	All Electric Rebates	$ 280,600.00	All Electric Home Rebates
		$ 484,996.17	

Exhibit II

RESPONSE OF SSVEC
TO ARIZONA CORPORATION COMMISSION
STAFF'S TWELFTH SET OF DATA REQUESTS
DOCKET NO. E-01575A-08-0328

December 11, 2008

STF 12.1 **Referring to the programs listed in Attachment A of Jack Blair's Testimony, Section I Overview under subsections A, B, C, and D, please provide a budget amount for each program listed.**

Response: **A. Residential Programs**

• Residential Energy Management	\$ 50,000
• Touchstone Energy® Efficient Home Program	\$175,000
• Energy Efficient Water Heater Rebates	\$ 25,000
• Energy Efficient New Home or Remodel Rebate	\$ 25,000
• Energy Efficient Heat Pump Rebate	\$ 20,000
• Energy Efficient Improvement Loan Program	\$200,000
• Time of Use Rate (tariff)	No Budget needed

B. Commercial and Industrial Programs

• Commercial and Industrial Energy Management	\$ 4,500
• C and I Energy Efficiency Improvement Loan Program	\$150,000
• Energy Efficient Water Heater Rebate	See above
• Energy Efficient Heat Pump Rebate	See above
• Time of Use Rates (tariff)	No Budget needed

C. Irrigation Programs

- Irrigation Energy Management (Time of Use/Control Rates – tariff)) No Budget needed

D. Advertising Program

- Advertising/ brochures $80,000

Prepared by: Jack Blair, Chief Member Services Officer
Sulphur Springs Valley Electric Cooperative, Inc.
311 East Wilcox Drive
Sierra Vista, AZ 85635

EXHIBIT
S-11
admitted

BEFORE THE ARIZONA CORPORATION COMMISSION

KRISTIN K. MAYES
Chairman
GARY PIERCE
Commissioner
PAUL NEWMAN
Commissioner
SANDRA D. KENNEDY
Commissioner
BOB STUMP
Commissioner

IN THE MATTER OF THE APPLICATION OF SULPHUR SPRINGS VALLEY ELECTRIC COOPERATIVE, INC. FOR A HEARING TO DETERMINE THE FAIR VALUE OF ITS PROPERTY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RETURN THEREON, TO APPROVE RATES DESIGNED TO DEVELOP SUCH RETURN AND FOR RELATED APPROVALS.	)	DOCKET NO. E-01575A-08-0328

SURREBUTTAL

TESTIMONY

OF

STEVE IRVINE

PUBLIC UTILITIES ANALYST IV

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

APRIL 3, 2009

TABLE OF CONTENTS

EXECUTIVE SUMMARY
SULPHUR SPRINGS VALLEY ELECTRIC COOPERATIVE, INC.
DOCKET NO. E-01575A-08-0328

This surrebuttal testimony addresses Sulphur Springs Valley Electric Cooperative, Inc.'s ("SSVEC" or "Company") Demand-Side Management ("DSM") program cost recovery and Renewable Energy Standard and Tariff ("REST") program cost recovery.

Staff makes the following conclusions and recommendations in response to SSVEC's rebuttal testimony:

- Staff agrees that Staff Recommendation No. 4 is now moot.
- Staff recommends that the Company file the DSM program expense reports **by** March 1st and September 1st rather than **on** March 1st and September 1st.
- Staff continues to support Recommendation No. 9, which is that SSVEC's annually proposed new DSM adjustor rate become effective on June 1st after approval by the Commission.
- Regarding the Company's response to Recommendation No. 10, it appears to Staff that the proposal by the Company envisions that a new program's expenses would be reported in the semi-annual reports but not included in the DSM adjustor for recovery until such time as the program was approved by the Commission. Should this interpretation of the Company's proposal be accurate, Staff agrees with the Company's proposal.
- Staff will endeavor to analyze the proposed programs including the information provided by the Company in support of its proposals and subsequently make recommendations regarding the proposed programs by way of supplemental testimony. Should time not permit sufficient analysis, Staff continues to recommend that the Company file a new application requesting approval of the new DSM programs that SSVEC is proposing in the instant application.
- Staff agrees with the Company's description of the appropriate treatment of the existing program expenses, 2007 and 2008 program expenses under Staff review, and 2009 expenses.

INTRODUCTION

Q. Please state your name, occupation, and business address.

A. My name is Steve Irvine. I am a Public Utilities Analyst IV employed by the Arizona Corporation Commission ("ACC" or "Commission") in the Utilities Division ("Staff"). My business address is 1200 West Washington Street, Phoenix, Arizona 85007.

Q. Have you previously docketed pre-filed written direct testimony in this case?

A. Yes.

Q. What is the scope of your surrebuttal testimony?

A. My surrebuttal testimony provides Staff's response to the rebuttal testimony of Sulphur Springs Valley Electric Cooperative, Inc.'s ("SSVEC" or "Company") witness Jack Blair regarding its Demand-side Management ("DSM") program and Renewable Energy Standard and Tariff ("REST").

DISCUSSION

Q. Have you reviewed the rebuttal testimony submitted by the Company in this case?

A. Yes. I reviewed Company witness Mr. Jack Blair's rebuttal testimony which responds to Staff's DSM and REST proposals.

Q. Does the Company agree with all of Staff's recommendations with regard to DSM and REST?

A. No. The Company states in rebuttal testimony that it agrees with many of Staff's DSM and REST recommendations; however, the Company disagrees with some of Staff's DSM recommendations.

Q. Please indicate which Staff recommendations on DSM and REST the Company disagrees with.

A. In rebuttal testimony, the Company has assigned numbers to the list of Staff recommendations included in Staff's direct testimony. This numbering system is helpful in identifying and dealing with contested recommendations. This testimony will make use of the Company's numbering system. The Company's rebuttal testimony mentions concerns with Staff's DSM Recommendation No. 4, DSM Recommendation No. 5, DSM Recommendations Nos. 7 – 11, and DSM Recommendation No. 13.

Q. What is Staff recommendation No. 4?

A. Staff recommends that should the Commission approve the Company's proposal to include some part of DSM program expense recovery in base rates, that the Commission also clarify that a negative DSM adjustor may be used to lower DSM program expense recovery below the rate included in base rates.

Q. What is the Company's response to this recommendation?

A. The Company comments that the recommendation is now moot because the Company has accepted Staff's recommendation that costs prudently incurred in connection with Commission-approved DSM activities be recovered entirely through a DSM adjustment tariff.

Q. What response does Staff have to the Company's rebuttal comments regarding Staff Recommendation No. 4?

A. Staff agrees that Staff Recommendation No. 4 is now moot because the Company's previous recommendation has changed.

Q. What is Staff Recommendation No. 5?

A. Staff recommends that SSVEC continue to report on DSM program expenses semi-annually.

Q. What is the Company's response to this recommendation?

A. The Company agrees to continue semi-annual reporting, but asks that it be able to file on March 1st and September 1st of each year. The September 1st report would report on DSM program expenses from January through June and the March report would report DSM program expenses from July through December.

Q. What response does Staff have to the Company's rebuttal comments regarding Staff Recommendation No. 5?

A. Staff agrees with this proposal since it would not result in a material change to the reporting, but recommends that the reports be filed *by* March 1st and September 1st of each year rather than *on* those dates. This recommendation contrasts with the Company's proposal to file *on* March 1st and September 1st. An order that directs a filing be made on a particular day can be burdensome for any Company. Unexpected circumstances can arise that make filing a document on a prescribed day difficult. The ability to file a document a day before, or several days before some benchmark date provides more flexibility to the applicant and gives the applicant the ability to file early if it is convenient. For this reason, Staff recommends that the Company file the DSM program expense reports **by** March 1st and September 1st rather than **on** March 1st and September 1st.

Q. What is Staff Recommendation No. 7?

A. Staff recommends that SSVEC's DSM program expense reports include the following: (i) the number of measures installed/homes built/participation levels; (ii) copies of marketing materials; (iii) estimated cost savings to participants; (iv) gas and electric savings as determined by the monitoring and evaluation process; (v) estimated environmental savings; (vi) the total amount of the program budget spent during the previous six months and, in the end of year report, during the calendar year; (vii) the amount spent since the inception of the program; (viii) any significant impacts on program cost-effectiveness; (ix) descriptions of any problems and proposed solutions, including movements of funding from one program to another; (x) any major changes, including termination of the program. Staff recommends SSVEC submit to the Commission, through Docket Control, a filing by April 1st of each year that includes its proposed new DSM adjustor rate and that the filing be considered and adjudicated by the Commission in Open Meeting.

Q. What is the Company's response to this recommendation?

A. The Company agrees to report semi-annual DSM program expenses and include the information set forth in the Staff recommendation. However, as mentioned previously in discussion of Recommendation No. 5, the Company reiterates its proposal to file its program expense reports on March 1st (as opposed to April 1st) and September 1st of each year. The Company also proposes that its annual adjustor reset also be made in the March 1st filing rather than on April 1st.

Q. What response does Staff have to the Company's rebuttal comments regarding Staff Recommendation No. 7?

A. Staff agrees with the Company's proposal in regard to the format of the DSM program expense reporting. Staff also agrees in principal with the Company's proposal regarding its timing of the filing of the expense and adjustor reset reports. As discussed previously, Staff notes that the Company is proposing that the expense reports and adjustor reset be filed on March 1^{st}. Staff has a concern related to using a specific filing date. As discussed previously, an order that directs a filing be made on a particular day can be burdensome for any Company. The ability to file a document a day before, or several days before some benchmark date gives the applicant the flexibility to file early if it is convenient. For this reason, Staff's recommends that the Company file the expense reports and adjustor reset filing **by** March 1^{st} and September 1^{st} rather than **on** March 1^{st} and September 1^{st}.

Q. What is Staff Recommendation No. 8?

A. Staff recommends that SSVEC's DSM adjustor rate be reset annually on June 1st of each year and that the per kWh rate be based upon currently projected DSM costs for that year (the year for which the calculation is being made), adjusted by the previous year's over- or under-collection, divided by projected retail sales (kWh) for that same year.

Q. What is the Company's response to this recommendation?

A. The Company in its rebuttal, comments on Staff Recommendations Nos. 7, 8, and 9 in a single response. For ease of discussion, Staff refers to the Company's single response to Staff Recommendations Nos. 7, 8, and 9 made in rebuttal testimony as the 'conjoined response'. Part of the conjoined response dealt directly with recommendation number 7, and has been discussed above. The remainder of the conjoined response deals with Staff Recommendation No. 9. In the conjoined response the Company agrees to the June 1^{st} reset date, but proposes certain conditions that would apply to the treatment of the reset. These conditions are contained in the excerpt from the Company's rebuttal testimony below. The Company's conjoined response does not appear to address the second part of Staff's Recommendation No. 8 that "the per kWh rate be based upon currently projected

DSM costs for that year (the year for which the calculation is being made), adjusted by the previous year's over- or under-collection, divided by projected retail sales (kWh) for that same year."

In the conjoined response, the Company includes the following (from pages 6 and 7 of Rebuttal Testimony of Company witness Jack Blair):

> However, SSVEC believes that the Commission should treat the June 1st reset date as a "hard" deadline. Although SSVEC has no objection to providing the Commission with the opportunity to consider and adjudicate the filing at Open Meeting as recommended by Staff, SSVEC has no control as to whether a staff report and proposed order is prepared and filed in time for the May Open Meeting. Given the additional 30 days of time that SSVEC is willing to provide Staff for its review, SSVEC believes that it is only appropriate that if the Commission does not approve the filing by June 1st, that the new adjustor will automatically become effective. SSVEC submits this is appropriate for several reasons. First, it provides the Commission the opportunity to consider and approve the matter at Open Meeting to the extent Staff believes it is necessary and appropriate. Second, with the additional 30 days that the Cooperative is proposing, Staff will have sufficient time to review the filing and make its recommendation to the Commission. If however, Staff is unable to review the filing in a given year, or, after reviewing the filing determines that it is not necessary that the matter be adjudicated by the Commission, SSVEC will not be placed at a disadvantage by having to wait to recover additional program expenses (or reduce the adjustor if appropriate) until such time that Staff and the Commission act on the filing, which is completely outside of the Cooperative's control. Should this occur, the Commission would still have another opportunity the next year to "true-up" the adjustor to take into consideration the two years that had gone by, as opposed to one year. SSVEC submits that under current circumstances, this is a reasonable and fair modification to the Staff recommendation.

Q. What response does Staff have to the Company's rebuttal comments regarding Staff Recommendation No. 8?

A. It appears that the Company agrees to Staff's Recommendation No. 8, with certain conditions placed on the June 1st reset. These conditions are addressed below in discussion of Staff Recommendation No. 9.

Q. What is Staff Recommendation No. 9?

A. Staff recommends that SSVEC's annually proposed new DSM adjustor rate become effective on June 1st after approval by the Commission.

Q. What is the Company's response to this recommendation?

A. The response is seen above in the excerpt from the Company's rebuttal testimony. The Company's response describes that implementation of the proposed DSM adjustor rate on June 1st should be automatic rather than contingent on Commission approval.

Q. What response does Staff have to the Company's rebuttal comments regarding Staff Recommendation No. 9?

A. Staff does not recommend that the DSM adjustor rate take effect automatically. As mentioned previously in Direct Testimony, adjudication of the filing by the Commission will allow the Commission to directly manage recovery of the DSM adjustor rate and the impact it has on ratepayers. Since changes to the DSM adjustor rate have a direct impact on customer bills, it is appropriate that the adjustor rate be set pursuant to Order of the Commission. Automatic implementation as a result of the Commission not issuing an order is not consistent with setting the rate pursuant to Order of the Commission. Staff continues to support Recommendation No. 9, which is that SSVEC's annually proposed new DSM adjustor rate become effective on June 1st after approval by the Commission.

Q. What is Staff Recommendation No. 10?

A. Staff recommends that SSVEC submit proposed programs to the Commission for approval.

Q. What is the Company's response to this recommendation?

A. The Company agrees with this recommendation, but requests that certain conditions apply. The Company argues that it should be permitted to operate any newly proposed programs prior to their approval by the Commission and report their expenses as part of its semi-annual reports. The Company suggests that should the Commission subsequently not approve the programs, the Company would not be permitted to recover such new program expenses. Upon approval of the program, the Company would be permitted to recover Commission-approved new program expenses through its DSM adjustor trued-up to the date it started offering the program at the next annual reset.

Q. What response does Staff have to the Company's rebuttal comments regarding Staff Recommendation No. 10?

A. It appears to Staff that this proposal by the Company envisions that a new program's expenses would be reported in the semi-annual reports but not included in the DSM adjustor for recovery until such time as the program was approved by the Commission. Should this interpretation of the Company's proposal be accurate, Staff agrees with the Company's proposal.

Q. What is Staff Recommendation No. 11?

A. Staff recommends that SSVEC file an application requesting approval of the new DSM programs SSVEC is proposing in the instant application.

Q. What is the Company's response to this recommendation?

A. The Company suggests that Staff endeavor to analyze and make recommendations on the new programs within this rate case and do so by providing written or oral supplements to testimony up to, and including, the time Staff presents its case at hearing.

Q. What response does Staff have to the Company's rebuttal comments regarding Staff Recommendation No. 11?

A. Staff will endeavor to analyze the proposed programs including the information provided by the Company in support of its proposals and subsequently make recommendations regarding the proposed programs by way of supplemental testimony. Should time not permit sufficient analysis, Staff continues to recommend that the Company file an application requesting approval of the new DSM programs that SSVEC is proposing in this application.

Q. What is Staff Recommendation No. 13?

A. Staff recommends that prudently incurred costs associated with approved DSM programs that have been factored into the Wholesale Power Cost Adjustor ("WPCA") account balance remain in the WPCA account balance.

Q. What is the Company's response to this recommendation?

A. The Company agrees with the recommendation and further clarifies its understanding of the treatment of account balances. The Company states that its understanding is that DSM program expenses that have not as yet been fully recovered through the wholesale power cost adjustor would remain in the wholesale power cost adjustor and continue to be recovered in that manner. The Company further states that with respect to 2007 and 2008 program expenses, that are currently being reviewed by Staff for approval pursuant to the

Company's last rate case decision (No. 58358), would also be recovered through the wholesale power cost adjustor once approved. Finally, the Company states that all 2009 approved program expenses would be reported and potentially recoverable through the new DSM adjustor.

Q. What response does Staff have to the Company's rebuttal comments regarding Staff Recommendation No. 13?

A. Staff agrees with the Company's description of the appropriate treatment of the existing program expenses, 2007 and 2008 program expenses under Staff review, and 2009 expenses.

Q. Does the Company respond to Staff's REST recommendations?

A. No.

SUMMARY OF STAFF CONCLUSIONS AND RECOMMENDATIONS

Q. Please provide a summary list of Staff's conclusions and recommendations.

- Staff agrees that Staff Recommendation No. 4 is now moot.
- Staff recommends that the Company file the DSM program expense reports **by** March 1st and September 1st rather than **on** March 1st and September 1st.
- Staff continues to support Recommendation No. 9, which is that SSVEC's annually proposed new DSM adjustor rate become effective on June 1st after approval by the Commission.
- Regarding the Company's response to Recommendation No. 10, it appears to Staff that the proposal by the Company envisions that a new program's expenses would be reported in the semi-annual reports but not included in the DSM adjustor for recovery until such time

as the program was approved by the Commission. Should this interpretation of the Company's proposal be accurate, Staff agrees with the Company's proposal.

- Staff will endeavor to analyze the proposed programs including the information provided by the Company in support of its proposals and subsequently make recommendations regarding the proposed programs by way of supplemental testimony. Should time not permit sufficient analysis, Staff continues to recommend that the Company file an application requesting approval of the new DSM programs SSVEC is proposing in the instant application.
- Staff agrees with the Company's description of the appropriate treatment of the existing program expenses, 2007 and 2008 program expenses under Staff review, and 2009 expenses.

Q. Does this conclude your surrebuttal testimony?

A. Yes, it does.

EXHIBIT
ALL-STATE LEGAL®
S-12
admitted

BEFORE THE ARIZONA CORPORATION COMMISSION

KRISTIN K. MAYES
Chairman
GARY PIERCE
Commissioner
PAUL NEWMAN
Commissioner
SANDRA D. KENNEDY
Commissioner
BOB STUMP
Commissioner

IN THE MATTER OF THE APPLICATION OF SULPHUR SPRINGS VALLEY ELECTRIC COOPERATIVE, INC. FOR A HEARING TO DETERMINE THE FAIR VALUE OF ITS PROPERTY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RETURN THEREON, TO APPROVE RATES DESIGNED TO DEVELOP SUCH RETURN AND FOR RELATED APPROVALS.	DOCKET NO. E-01575A-08-0328

DIRECT

TESTIMONY

OF

JULIE MCNEELY-KIRWAN

PUBLIC UTILITIES ANALYST IV

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

JANUARY 26, 2009

TABLE OF CONTENTS

EXHIBIT

EXECUTIVE SUMMARY
SULPHUR SPRINGS VALLEY ELECTRIC COOPERATIVE, INC.
DOCKET NO. E-01575A-08-0328

The base cost of power should be established at $0.072127 per kWh, as proposed by Sulphur Springs Valley Electric Cooperative, Inc. ("SSVEC").

To limit potential future rate shocks, SSVEC should be required to submit future increases in its Wholesale Power Cost Adjustment ("WPCA") rate to the Commission for approval. SSVEC should also be required to establish positive and negative thresholds for its bank balance.

The WPCA mechanism should be revised to allow recovery of costs associated with owned generation. The name of the WPCA mechanism should be changed to "Wholesale Power and Fuel Cost Adjustment" ("WPFCA") mechanism to reflect this change. DSM cost recovery should be moved out of the WPCA mechanism and into a specific DSM adjustor. An officer of SSVEC should sign off on SSVEC's adjustor reports as true and accurate to the best of his or her information.

SSVEC should be allowed to eliminate the construction allowance for line extensions in all classes.

SSVEC's Service Conditions should be revised to make clear that it is impermissible to disconnect customers falling under Arizona Administrative Code R14-2-211.5.

SSVEC should make additional revisions to its Service Conditions in accordance with Staff's testimony.

INTRODUCTION

Q. Please state your name, occupation, and business address.

A. My name is Julie McNeely-Kirwan. I am a Public Utilities Analyst IV employed by the Arizona Corporation Commission ("ACC" or "Commission") in the Utilities Division ("Staff"). My business address is 1200 West Washington Street, Phoenix, Arizona 85007.

Q. Briefly describe your responsibilities as a Public Utilities Analyst IV.

A. In my capacity as a Public Utilities Analyst IV I review and analyze applications filed with the Commission, and prepare memoranda and proposed orders for Open Meetings. My duties include tracking monthly fuel adjustor reports and reviewing annual utility affiliated interest reports for compliance. My duties have also included preparing written testimony in the UNS Gas and UNS Electric rate cases, as well as testifying during the UNS Gas and UNS Electric rate case hearings.

Q. Please describe your educational background and professional experience.

A. In 1979, I graduated Magna Cum Laude from Arizona State University, receiving a Bachelor of Arts degree in History. In 1987, I received a Master's Degree in Political Science from the University of Wisconsin, Madison. I have been employed by the Commission since September of 2006.

Q. What is the subject matter of this testimony?

A. This testimony will present Staff's analysis and evaluation of the base cost of power, the purchased power adjustor and the Service Conditions.

BASE COST OF PURCHASED POWER

Q. What is the Cooperative's proposed base cost of power?

A. The Cooperative's proposed base cost of power is $0.072127 per kWh. This was arrived at by dividing Sulphur Springs Valley Electric Cooperative, Inc.'s ("SSVEC") Adjusted Test Year power costs by its Adjusted Test Year kWh sold. (See SSVEC's Schedule N-3.0.)

Q. Does Staff have concerns regarding the Cooperative's proposed base cost of power based on Test Year data?

A. Yes. Test Year rate increases from the Arizona Electric Power Cooperative, Inc. ("AEPCO") and Southwest Transmission Cooperative ("SWTC"), Inc., both occurring in September 2007, were included in SSVEC's base cost calculations, but not on an annualized basis. This potentially understates actual power costs going forward.

Q. Were there any changes since January that have impacted the cost of power for SSVEC?

A. In January 2008 SSVEC changed from an All Requirements Member of AEPCO to a Partial Requirements Member ("PRM"), meaning that part of SSVEC's power supply could be purchased from sources other than AEPCO. This includes purchases from the open market, where energy cost has been volatile. In addition, there have been increases since January 2008 to SSVEC's costs for power.

Staff notes that SSVEC's actual power costs since January 2008 have been consistently higher than $0.072127 per kWh.

Q. Please provide details concerning the actual cost of power since January 2008, when SSVEC became a partial requirements member.

A. During the period from January 2008 through October 2008 the actual cost of power has ranged from a low of $0.070363 per kWh in February to a high of $0.104357 per kWh in June. See the table, below:

Table 1: Unit Cost of Purchased Power (2008)

Jan-08	$0.072402
Feb-08	$0.070363
Mar-08	$0.082044
Apr-08	$0.076848
May-08	$0.079511
Jun-08	$0.104357
Jul-08	$0.092795
Aug-08	$0.089761
Sept-08	$0.07052
Oct-08	$0.08087

Q. Did Staff calculate the average cost of power for SSVEC since SSVEC became a partial requirements customers?

A. Yes. SSVEC's average cost of power from January 2008 through October 2008 was $0.08215 per kWh.

Q. How did Staff arrive at this number?

A. Staff calculated the average cost of power by totaling SSVEC's purchase power costs from its monthly adjustor reports for January through October 2008, subtracting out demand-side management ("DSM") costs, and then dividing the resulting number by the number of kilowatt hours ("kWh") sold to customers during the January through October period. This number includes SSVEC's actual, rather than projected, costs during its period as a PRM customer of AEPCO, and includes post-Test Year increases in the cost of power. (Post-Test Year data and increases are components of the actual cost of power for SSVEC since becoming a partial requirements customer.)

Q. Why did Staff subtract the DSM costs?

A. Because DSM costs arise from the funding of conservation and efficiency programs and, although currently recovered through the purchased power adjustor, are not a component of the cost of power.

Q. Based on its assessment of SSVEC's actual cost of power since January 2008, is Staff recommending a higher base cost of power than that proposed by the Cooperative?

A. No. Future fuel costs can not be predicted with sufficient certainty. Currently, there are both upward and downward pressures on energy costs. Moreover, as a partial requirements member SSVEC may be able to enter into less expensive long-term energy contracts.

Staff recommends that the base cost of power be established at $0.072127 per kWh, as proposed by SSVEC.

Q. Are there any other factors which may influence SSVEC's costs going forward?

A. A review of SSVEC's procurement practices is being conducted by Staff as part of the current rate case. This review may identify opportunities to enhance SSVEC's procurement process and positively impact costs.

Q. If power costs are in excess of the recommended base cost would SSVEC still be able to recover its fuel and purchased power costs? Alternatively, if costs decrease would SSVEC be able to return over-collections to ratepayers?

A. Yes. SSVEC would be able to resolve any difference between its base cost of power and its actual purchased power costs through its Wholesale Power Cost Adjustment ("WPCA") mechanism.

Q. Does Staff have any concerns about utilizing the WPCA mechanism to adjust for power costs that differ from the base cost?

A. Yes. Large changes to the WPCA mechanism make the cost of power less predictable for customers, and may result in rate shocks. Staff recommendations for managing the adjustor to limit unpredictability are discussed in the next section, on the Wholesale Power Cost Adjustment mechanism.

WHOLESALE POWER COST ADJUSTMENT ("WPCA") MECHANISM

Q. What is the WPCA mechanism?

A. The WPCA mechanism is a purchased power adjustor that uses charges or credits to compensate for the difference between the base cost of power and the actual cost of wholesale power. A bank balance tracks a utility's over-collections and under-collections for the cost of power and transmission. The SSVEC WPCA mechanism is adjusted periodically to reduce large positive or large negative balances, returning over-collections to ratepayers, or increasing the WPCA charge to pay down under-collections. Interest is not applied to either over- or under-collected balances.

Q. Does SSVEC have the authority to manage its bank balance by changing the WPCA rate?

A. Yes. SSVEC currently has the authority to change the WPCA rate without Commission approval.

Q. Please describe SSVEC's recent use of the WPCA mechanism.

A. From January 2006 through September 2008 the SSVEC adjustor has ranged from minus $0.00100 per kWh (which returned an over-collected bank balance to ratepayers) to the current adjustor rate of $0.04000, which adds four cents per kWh over the current base cost of $0.05897. Please see the table below for additional details:

Table 2: Changes to the WPCA Rate 4/06-8/08

Date of change	Adjustment from/to	Bank Balance[1]
April 2006	($0.00100) to $0.00881	$403,637 under-collected
November 2006	$0.00881 to $0.01106	$1,002,969 under-collected
February 2007	$0.01106 to $0.01606	$1,919,641 under-collected
April 2007	$0.01606 to $0.01975	$1,031,412 under-collected
January 2008	$0.01975 to $0.00805	$1,585,042 over-collected
May 2008	$0.00805 to $0.01975	$481,288 under-collected
August 2008	$0.01975 to $0.04000	$4,305,485 under-collected

Q. Describe the impact of changes to the WPCA mechanism on the bank balance.

A. From December 2007 through July 2008 the unit cost of purchased power, per kWh, was higher than the cost per kWh being collected from customers, despite a May increase from $0.00805 to $0.01975 in the WPCA rate. For example, in July 2008, the unit cost of purchased power per kWh was $0.09279, while the total rate being collected from customers was $0.07872. (This amount includes the current base cost of power of $0.05897 per kWh and $0.01975 collected through the WPCA mechanism.) With collections from customers below actual costs, by July 2008 the under-collected bank balance had risen to $4,305,485.48, as indicated above. (Compare this to the July 2007 bank balance of $17,340.05; however, $502,414.36, or 11.67%, of the $4,305,485.48 balance in July 2008 arose from approved DSM charges added to the bank balance in July 2008).

When the WPCA surcharge was increased from $0.01975 to $0.4000 in August 2008, this increased the total rate collected from customers per kWh to $0.09897, while the unit cost of purchased power per kWh was $0.089761; with collections now exceeding the unit cost

[1] Balance cited in Table 2 in for the beginning of the month in which the WPCA rate was changed.

of purchased power, SSVEC began to reduce its large under-collection. As of October 2008 SSVEC's under-collected bank balance had decreased to $1,055,935.96.

Exhibit 1, attached to this testimony, reflects the recent history of the bank balance and its increasing volatility since January 2008.

Q. What has been the impact of recent increases to the WPCA rate on SSVEC customers?

A. With an increase from $0.00805 to $0.01975 in April, and an increase from $0.01975 to $0.04000 in August, SSVEC customers experienced a total $0.03195 increase to their per kWh cost between April and August 2008.

Q. How would this impact an average residential customer's bill?

A. Average usage in August was 873 kWh for Residential customers. (40,441 Residential customers using a total of 35,319,400 kWh.) The total $0.03195 increase would add $27.90 to an average August bill for Residential customers.

The $0.01975 to $0.0400 increase in August accounted for $17.69 of the $27.90. August is a peak usage month, which magnifies the impact of a higher WPCA, but also reduces an under-collected bank balance more rapidly.

Q. Is Staff proposing any changes to the way in which SSVEC manages its WPCA mechanism?

A. Yes. Since January 2008, when SSVEC became a partial requirements member, the Cooperative's energy costs have been more volatile. The greater volatility impacts the bank balance and, consequently, the WPCA rate. In order to manage the WPCA rate, Staff recommends that, in the future, SSVEC submit proposed increases to the WPCA rate to the Commission for approval. Submitting proposed increases for approval would ensure that impacts to the Cooperative's customers are regulated.

Staff does not recommend that SSVEC be required to seek approval for decreases to its WPCA rate.

Q. Is Staff proposing any other changes to the way in which SSVEC manages its WPCA mechanism?

A. Yes. Staff is recommending that set thresholds be established to trigger changes in the WPCA mechanism rate for both over- and under-collected bank balances.

With respect to under-collected bank balances, SSVEC must file an application to increase the WPCA rate either when the bank balance reaches the threshold for under-collected balances for two consecutive months, or when it reasonably anticipates that the threshold will be reached within six months and would continue at or above the threshold for two or more consecutive months.

With respect to over-collections, SSVEC may return over-collected bank balances to its customers at any time, except it must use the WPCA mechanism to return over-collections once the threshold is reached and remains over the threshold for two consecutive months.

Q. What are the benefits of SSVEC establishing set thresholds for its WPCA mechanism?

A. With respect to under-collections, a set threshold would limit the size of any negative bank balance that could accumulate. This would have the effect of limiting increases to the WPCA mechanism, thereby limiting rate shocks to the customers.

With respect to over-collections, a set threshold would ensure that positive bank balances would be returned to customers in a timely and predictable fashion.

Another advantage to set thresholds is that a written, established policy concerning thresholds makes the functioning of the WPCA mechanism more transparent and predictable.

Q. What thresholds is Staff proposing for the WPCA mechanism?

A. Staff recommends a $2 million threshold for under-collections and a $1 million threshold for over-collections.

Q. How were these thresholds determined?

A. The $2 million limit on under-collections is designed to keep increases to the WPCA mechanism low enough to limit rate shocks, while the $1 million limit on over-collections places a reasonable limit on how much SSVEC can owe each Residential customer before it begins to refund an over-collection. Both thresholds are calculated based on how much an individual Residential customer would owe, or be owed, for that single customer's "share" of the bank balance. At $2 million, a Residential customer's share of an under-collected bank balance would be approximately $40, while at $1 million the average SSVEC customer's share of an over-collection would be approximately $20.

Q. What public interest is served by requiring SSVEC to seek Commission approval for increases to its adjustor, or for imposing thresholds on SSVEC's adjustor bank balances?

A. The Arizona Corporation Commission has the authority, and the obligation, to set fair, just, and reasonable rates for Arizona utility ratepayers, whether the utility providing service is investor-owned or a cooperative. This rate-setting includes regulating the ways in which purchased power or fuel costs are passed on to customers, because the structure of these pass-throughs have an impact on ratepayers. In this case, particularly given SSVEC's recent transition to partial requirements status, it is in the public interest to regulate the manner in which costs are passed through the WPCA mechanism, because doing so protects SSVEC's members from rate shocks. It is also in the public interest to establish thresholds; thresholds provide an additional limit on rate shocks, and ensure that the bank balance is maintained at a reasonable level, even with SSVEC's greater exposure to fluctuating market costs as a partial requirements member.

Q. Is the Cooperative proposing any changes that would affect the WPCA?

A. Yes. The Cooperative is proposing to include a pass-through of fuel costs that may arise if SSVEC were to have its own generating units.

Q. Does the inclusion of FERC Account 555 in the WCPA mechanism presume the prudency of those fuel costs?

A. No. To the extent that SSVEC were to own and operate its own generation, the fuel costs would likely be includable for pass-though; however, in no way should that be construed as a determination of prudency regarding those fuel costs.

Q. Why is the Cooperative proposing this change to the WPCA?

A. Prior to January 2008 AEPCO supplied SSVEC with all its power under a full requirements contract. In January 2008 SSVEC became a partial requirements member of AEPCO, meaning that some portion of SSVEC's future power supply may come from owned generation sources, which require fuel, or through purchased power agreements, where additional transmission costs would be incurred. The Cooperative has proposed that the WPCA mechanism be revised to allow these costs to be recovered.

Q. Does Staff agree with this proposed change?

A. Yes. It is logical for the costs associated with both acquiring and generating power to be recovered through the same adjustor mechanism. One benefit is that it clarifies the overall cost of power. Another benefit is that the adjustor mechanism can be modified to limit rate shocks to customers arising from the volatility of power costs. (Through, for example, the use of bank balance thresholds. See Staff's additional testimony on this subject, above.)

Q. What cost components does SSVEC propose to include in its WPCA?

A. The FERC Accounts SSVEC proposes to include in its WPCA mechanism consist of the following:

- Steam Power Generation – Operation, FERC Accounts 500-507;
- Steam Power Generation – Maintenance, FERC Accounts 510-514;
- Nuclear Power Generation -- Operation, FERC Accounts 517-525;
- Nuclear Power Generation -- Maintenance, FERC Accounts 528-532;
- Hydraulic Power Generation -- Operations, FERC Accounts 535-540;
- Hydraulic power Generation -- Maintenance, FERC Accounts 541-545;
- Other Power Generation – Operation, FERC Accounts 546-550;

- Other Power Generation – Maintenance, FERC Accounts 551-554; and
- Purchased Power, FERC Accounts 555-557.

Q. Does Staff agree with the list of FERC accounts SSVEC proposes to include in its revised WPCA mechanism?

A. No. SSVEC's proposed list of FERC accounts is overbroad and includes costs that do not belong in a power and fuel adjustor, such as maintenance and rent costs.

Q. What cost components should be included in the WPCA mechanism?

A. The SSVEC power and fuel adjustor should include costs directly related to the purchase, generation or transmission of power. These include the following FERC Accounts: 501 (fuel costs for steam power generation, less legal fees, less fixed fuel costs except for gas reservation), 518 (fuel costs for nuclear power generation, less Independent Spent Fuel Storage Installation ("ISFI") regulatory amortization), 547 (fuel costs for other power generation), 555 (purchased power costs – demand and energy), and 565 (transmission of electricity by others, both firm and non-firm). Power supply costs directly assignable to special contract customers would not be included in the calculation.

Q. Why does Staff include wheeling costs from FERC Account 565?

A. With respect to FERC Account 565, both firm and non-firm wheeling costs are related to the transmission of power to SSVEC for resale. As such, these costs are appropriate for recovery through the power and fuel adjustor mechanism. In addition, if only non-firm wheeling costs were included in the adjustor, the manner of cost recovery (more immediate through an adjustor) could influence the type of contract negotiated, when the only consideration in selecting and negotiating contracts should be the best deal for ratepayers.

Q. Should capital or legal costs go through the SSVEC WPCA mechanism?

A. No, and SSVEC has stated that capital costs would not be recovered through the revised adjustor mechanism. (Response to JKM 6.4) Legal costs are another example of costs that should not go through the WPCA, as these are not appropriate for a power and fuel adjustor.

Q. Is Staff recommending any changes to the WPCA mechanism, if it is revised to provide for recovery of owned-generation fuel and costs related to purchased power contracts?

A. Yes. Staff recommends that the name of the Wholesale Power Cost Adjustment mechanism be changed to the "Wholesale Power and Fuel Cost Adjustment ("WPFCA")" mechanism. The new name would be more descriptive of the types of costs recovered through the revised adjustor.

Q. Has the Cooperative proposed any other changes that would affect the WPCA?

A. Yes. SSVEC's DSM costs are currently recovered through the Cooperative's WPCA mechanism. SSVEC proposes to move recovery of its DSM costs out of the WPCA, and to create a new DSM adjustment mechanism to recover a portion of its DSM costs. (Please see Staff Witness Steve Irvine's testimony regarding SSVEC's proposal to roll a portion of Test Year DSM costs into base rates.)

Q. Is Staff opposed to moving DSM costs out of SSVEC's WPCA mechanism?

A. No. Staff concurs that DSM funding should be moved out of the WPCA mechanism and into a separate adjustor specifically designated to recover DSM costs. To include DSM funding in the WPCA mechanism obscures both the cost of power and the cost of DSM.

Separate adjustors provide specific accountings for both elements, making the actual cost of each as clear as possible for ratepayers.

Q. Are there any Staff recommendations with respect to reporting on SSVEC's fuel adjustor reports?

A. Yes. Staff recommends that an SSVEC officer sign off on SSVEC's WPFCA reports. This process is the same as Commission requirements for other entities in other rate cases. An SSVEC officer should certify that all information provided in SSVEC's purchased power and WPFCA reports is true and accurate to the best of his or her information and belief.

SERVICE CONDITIONS

Q. Has SSVEC revised its Service Conditions as part of the current rate case?

A. Yes. SSVEC states that most of its changes were intended to clarify the Service Conditions, make them consistent, ensure compliance with Commission rules and incorporate changes in technology since the last rate case. The major proposed change eliminates the construction allowance for line extensions for all classes.

Q. Does Staff agree with elimination of the construction allowance for line extensions?

A. Yes. SSVEC reports that costs associated with growth have "increased dramatically" in recent years. Eliminating free footage would reduce SSVEC's costs associated with growth, reduce the need for future rate increases and reduce the debt SSVEC incurs to provide service.

Q. Does Staff have any other concerns regarding the Service Conditions?

A. Yes. Staff recommends that SSVEC's Service Conditions be revised to make clear that it is *impermissible to disconnect* customers falling under Arizona Administrative Code R14-2-211.5. To ensure that this is understood by both employees and customers of SSVEC, Staff recommends that the phrase ", with the exception of customers falling under R14-2-211.5," be inserted on page 27 of the Service Conditions, at 2.20.3.A., after the word "reason.".

Q. Why is it impermissible to disconnect customers falling under this classification?

A. Because this is a uniquely vulnerable customer class, who, if disconnected, could suffer grave impacts to health, or even die.

Q. Does Staff have any changes to recommend to SSVEC's Service Conditions with respect to identifying responsible parties?

A. Yes. On page 8, 2.3.4, <u>Identification of Responsible Party</u>, insert the word "notarized" following the phrase "shall furnish to SSVEC"; in the same sentence following the phrase "written approval from" delete the word "that" and insert the phrase "the billed." The revised sentence should read as follows: "Any Person applying for Electric Service to be connected in the name of or in care of another Customer shall furnish to SSVEC notarized written approval from the billed Customer guaranteeing payments of all bills." These changes in language should assist in limiting fraud.

Q. Does Staff have any changes to recommend to SSVEC's Service Conditions with respect to service calls?

A. Yes. On page 14, 2.5.6.A, <u>Service Calls During Regular Business Hours</u>, add the following sentence: "Reasonable efforts will be made to advise the Customer about the responsibility of such charges before the service calls starts." This language is part of the existing tariff and should be retained.

Q. Does Staff have any changes to recommend to SSVEC's Service Conditions with respect to prepaid metering services?

A. Yes. On pages 22-23, 2.16.3, <u>Prepaid Metering Services</u>, SSVEC should add a closing sentence directing interested customers to a source for additional information on these services.

Q. Does Staff have any changes to recommend to SSVEC's Service Conditions with respect to meter testing?

A. Yes. On page 33, 3.6.3., <u>Metering Testing Requested By The Customer</u>, the entry should remain unchanged from SSVEC's current tariff, which complies with the Arizona Administrative Code R14-2-409. Retaining this language makes clear that customers requesting meter testing will not be charged, if testing shows that the meters requested for testing are more than 3% inaccurate.

Q. Does this conclude your direct testimony?

A. Yes, it does.

SUMMARY OF STAFF RECOMMENDATIONS

- Staff recommends that the base cost of power be established at $0.072127per kWh, as proposed by SSVEC.
- Staff recommends that, in the future, SSVEC submit proposed increases to the power and fuel adjustor to the Commission for approval to ensure that impacts to the Cooperative's

customers are regulated. Staff does not recommend that SSVEC be required to seek approval for decreases to its power and fuel adjustor.

- Staff recommends a $2 million threshold for under-collections and a $1 million threshold for over-collections for SSVEC's power and fuel adjustor.
- Staff recommends that the power and fuel adjustor be revised to allow recovery of costs for the following FERC Accounts: 501, 518, 547, 555 and 565.
- Staff recommends that DSM funding should be moved out of the WPCA mechanism and into a separate adjustor specifically designated to recover DSM costs.
- Staff recommends that the name of the WPCA mechanism be changed to the WPFCA mechanism.
- Staff recommends that an SSVEC officer sign off on SSVEC's WPFCA reports. This process is the same as Commission requirements for other companies in other rate cases. An SSVEC officer should certify that all information provided in SSVEC's WPFCA reports is true and accurate to the best of his or her information and belief.
- Staff recommends that SSVEC revise its Service Conditions to eliminate free footage.
- Staff recommends that SSVEC's Service Conditions be revised to make clear that it is impermissible to disconnect customers falling under Arizona Administrative Code R14-2-211.5. To ensure that this is understood by both employees and customers of SSVEC, Staff recommends that the phrase ", with the exception of customers falling under R14-2-211.5," be inserted on page 27 of the Service Conditions, at 2.20.3.A., after the word "reason."
- Staff recommends that SSVEC revise its proposed Service Conditions as follows: On page 8, 2.3.4, <u>Identification of Responsible Party</u>, insert the word "notarized" following the phrase "shall furnish to SSVEC"; in the same sentence following the phrase "written approval from" delete the word "that" and insert the phrase "the billed." The revised sentence should read as follows: "Any Person applying for Electric Service to be

connected in the name of or in care of another Customer shall furnish to SSVEC notarized written approval from the billed Customer guaranteeing payments of all bills." These changes in language should assist in limiting fraud.

- Staff recommends that SSVEC revise its proposed Service Conditions as follows: On page 14, 2.5.6.A, Service Calls During Regular Business Hours, add the following sentence: "Reasonable efforts will be made to advise the Customer about the responsibility of such charges before the service calls starts." This language is part of the existing tariff and should be retained.
- Staff recommends that SSVEC revise its proposed Service Conditions as follows: On pages 22-23, 2.16.3, Prepaid Metering Services, SSVEC should add a closing sentence directing interested customers to a source for additional information on these services.
- Staff recommends that SSVEC revise its proposed Service Conditions as follows: On page 33, 3.6.3., Metering Testing Requested By The Customer, the entry should remain unchanged from SSVEC's current tariff, which complies with the Arizona Administrative Code R14-2-409.

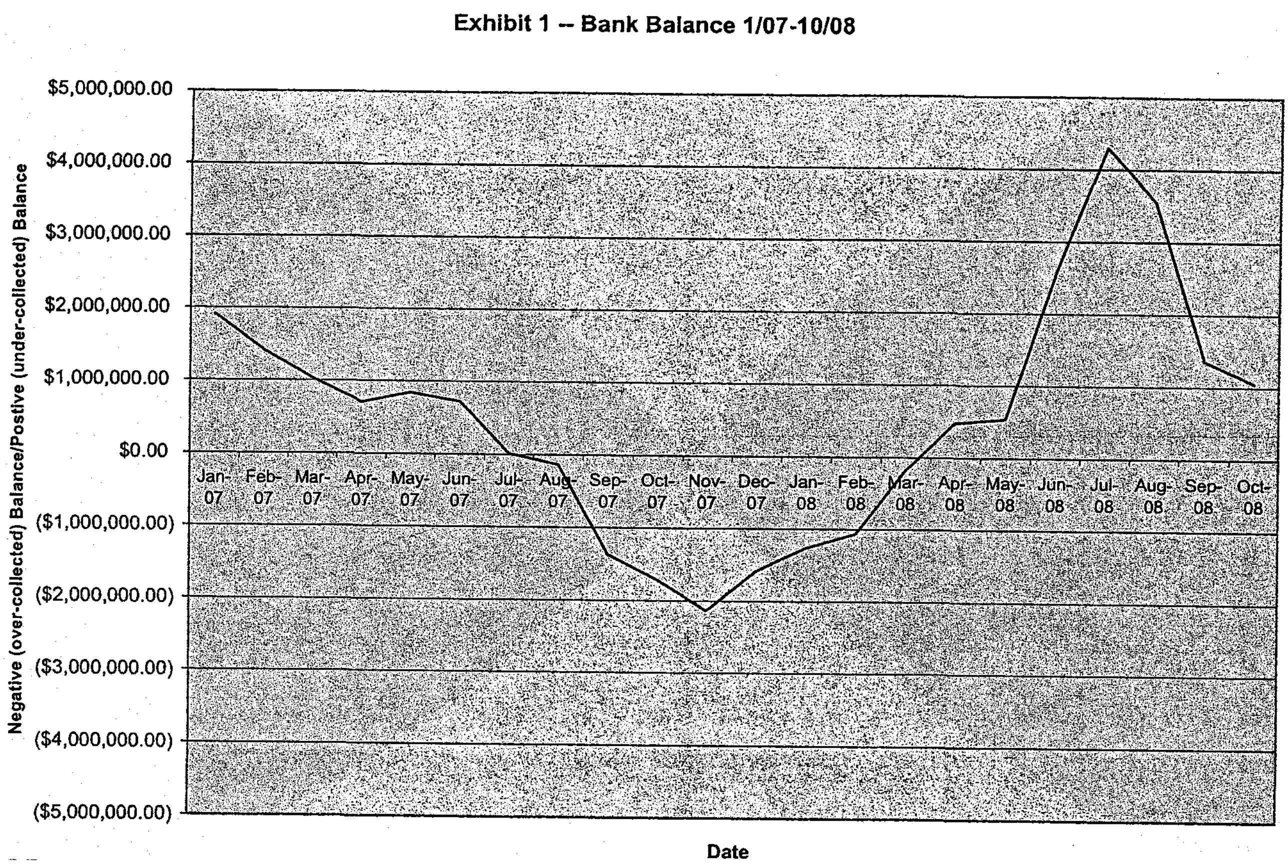


Exhibit 1 -- Bank Balance 1/07-10/08
$5,000,000.00
$4,000,000.00
$3,000,000.00
$2,000,000.00
$1,000,000.00
$0.00
($1,000,000.00)
($2,000,000.00)
($3,000,000.00)
($4,000,000.00)
($5,000,000.00)
Negative (over-collected) Balance/Postive (under-collected) Balance
Jan-07 Feb-07 Mar-07 Apr-07 May-07 Jun-07 Jul-07 Aug-07 Sep-07 Oct-07 Nov-07 Dec-07 Jan-08 Feb-08 Mar-08 Apr-08 May-08 Jun-08 Jul-08 Aug-08 Sep-08 Oct-08
Date

EXHIBIT
S-13
admitted

BEFORE THE ARIZONA CORPORATION COMMISSION

KRISTIN K. MAYES
Chairman
GARY PIERCE
Commissioner
PAUL NEWMAN
Commissioner
SANDRA D. KENNEDY
Commissioner
BOB STUMP
Commissioner

IN THE MATTER OF THE APPLICATION OF SULPHUR SPRINGS ELECTRIC COOPERATIVE, INC.FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF SULPHUR SPRINGS ELECTRIC COOPERATIVE, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA.	DOCKET NO. E-01575A-08-0328

SURREBUTTAL

TESTIMONY

OF

JULIE MCNEELY-KIRWAN

PUBLIC UTILITIES ANALYST IV

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

APRIL 3, 2009

TABLE OF CONTENTS

Page

EXECUTIVE SUMMARY
SULPHUR SPRINGS VALLEY ELECTRIC COOPERATIVE, INC.
DOCKET NO. E-01575A-08-0328

This Surrebuttal Testimony addresses issues raised by Sulphur Springs Valley Electric Cooperative ("SSVEC"), in its Rebuttal Testimony, including the Cooperative's counter-proposals concerning Staff's recommendations regarding the Wholesale Power Cost Adjustment mechanism.

It is Staff's position that SSVEC's future power costs are unpredictable and may prove volatile, and that requiring Commission approval for future increases would aid in limiting rate shocks to SSVEC's customers. Approval should be required for all increases, but not for decreases; over-collections should be limited by instituting an upper threshold of $1 million for the SSVEC bank balance. The threshold for under-collections should remain at the $2 million limit recommended in Staff's Direct Testimony, but the Cooperative should be allowed to file for an increase based on reasonable projections that the upper threshold would be reached within six months and remain at or over that threshold for two months.

INTRODUCTION

Q. Please state your name, occupation, and business address.

A. My name is Julie McNeely-Kirwan. I am a Public Utilities Analyst IV employed by the Arizona Corporation Commission ("ACC" or "Commission") in the Utilities Division ("Staff"). My business address is 1200 West Washington Street, Phoenix, Arizona 85007.

Q. Have you previously filed testimony in this docket?

A. Yes. I filed Direct Testimony addressing SSVEC's base cost of purchased power, its wholesale power cost adjustment ("WPCA") mechanism, and its service conditions.

Q. What is the subject matter of this Surrebuttal Testimony?

A. Staff's Surrebuttal Testimony will address the Cooperative's objection to Staff's recommendation that SSVEC be required to obtain approval from the Commission in order to increase its WPCA rate. Staff's Surrebuttal Testimony will also address the Cooperative's issues and counter-proposal concerning thresholds recommended by Staff for the SSVEC fuel bank.

STAFF'S PROPOSAL THAT SSVEC BE REQUIRED TO SEEK COMMISSION APPROVAL FOR INCREASES TO ITS ADJUSTOR RATE

Q. SSVEC contends that the Commission's regulation of AEPCO, along with its authority to address the WPCA mechanism in this rate filing, make requiring Commission approval for increases to the WPCA rate "an unnecessary duplication of regulation." Does Staff concur?

A. No. The Commission's regulation of AEPCO and authority over the WPCA mechanism do not guarantee that SSVEC's future power costs will be passed through its adjustor in a just and reasonable fashion, particularly in light of its transition to partial requirements status. This transition has increased chances that SSVEC's future power costs will be more unpredictable, making additional regulatory oversight important.

Q. Why does this transition require more regulatory oversight, given that SSVEC obtains most of its power from AEPCO?

A. Although increases from AEPCO were a factor in increased costs for SSVEC during 2008, it is by no means clear that increases from AEPCO were the primary cause of SSVEC's increased power costs (as SSVEC contends). What is clear is that SSVEC's third party power purchases, made because it transitioned to a partial requirements contract, played a very significant role in SSVEC's increased power costs. (Please see the Direct and Surrebuttal Testimony of Staff Witness Jerry Mendl.)

Clearly, the transition to partial requirements status made the cost of SSVEC's power supply more volatile. Since these costs are passed on to SSVEC's customers, requiring Commission approval for increases in its adjustor rate would assist in ensuring that SSVEC recovers these less-predictable fuel and purchased power costs in a manner that limits rate shocks to SSVEC's customers.

Q. How would requiring Commission approval for increases in its adjustor rate assist in ensuring that SSVEC recovers its fuel and purchased power costs in a manner that would limit rate shocks to SSVEC customers?

A. First, review of an application seeking an increase to the adjustor rate would allow the Commission to ensure that the request was appropriate, and that the supporting projections, if any, were reasonable. Second, the Commission could assist in designing cost recovery to limit rate shocks, for example, by instituting graduated increases and by limiting increases during peak-usage months.

Q. Is Staff aware of any recent events that support the conclusion that SSVEC should seek Commission approval for increases to its WPCA rate?

A. Yes. SSVEC transitioned to a partial requirements contract in January 2008. By July 2008, SSVEC's under-collection grew to over $4.3 million and, to pay down this balance, SSVEC instituted large increases to its adjustor rate during high-usage months, significantly impacting ratepayer bills.

Q. Does Staff believe that SSVEC's cost of power purchases could become even less predictable over time?

A. Yes. First, even now a significant portion – approximately 20 percent -- of SSVEC's power is purchased in the wholesale market, meaning that one-fifth of its supply comes from sources that may not be regulated by the Commission. Second, although SSVEC is currently taking approximately 80 percent of its supplies from AEPCO, under the partial requirements contract SSVEC is only obligated to purchase its Minimum Base Capacity, or approximately 47 percent of its energy needs. (SSVEC is also obligated to purchase a variable minimum demand each month.) SSVEC, therefore, has the option of greatly reducing its reliance on AEPCO, should it decide to do so, and this could make SSVEC's cost of power purchases even less predictable.

Q. Has SSVEC indicated that it plans to decrease its reliance on AEPCO?

A. No. SSVEC has indicated that over the next five years (2009-2013) it "intends to purchase its full entitlement to Schedule A energy from AEPCO" as long as "Schedule A energy remains the lowest cost energy available to SSVEC." (See response to STF 17.4) Based on this cost assumption, SSVEC estimates that it will purchase between 75.3 percent and 88.3 percent of its power supply from AEPCO during those years.

It should be noted that Schedule A energy may not remain the lowest cost energy. Should Schedule A power increase in cost relative to other sources, SSVEC would presumably reduce its reliance on AEPCO as a result. Staff also notes that as SSVEC experiences growth, acquires unit ownership interest, or self-builds peaking projects, it may buy a smaller percentage of its power supply from AEPCO.

Whatever SSVEC's current intentions, changing market conditions, including changes in demand, price or availability, could cause the Cooperative to shift from its reliance on AEPCO. As indicated above, SSVEC already has the ability to decrease its reliance under the partial requirements contract, should it elect to do so. It is Staff's position that there are too many variables to reliably predict what SSVEC's future purchasing patterns will be, since its purchasing must be conditioned on what is prudent and in the best interests of rate payers.

Q. What are the possible impacts of changes in SSVEC's purchasing patterns?

A. Purchases from the wholesale market are likely to increase the amount of power purchased from sources that are unregulated by the Arizona Corporation Commission, and the future costs of power from unit ownership interests or self-built peaking projects are unknown at this time.

In general, a decreased reliance on AEPCO as a supplier makes SSVEC's future cost of power more unpredictable and potentially more volatile.

Q. Does Staff agree with SSVEC's proposal that "SSVEC be allowed to adjust its WPCA rate without Commission approval unless such adjustment would result in a cumulative annual increase in the total average rate collected from customers per kWh greater than 10%"?

A. No. Staff opposes SSVEC's proposal. SSVEC provided information and an example to clarify the question of how such a limit would work in practice, indicating how the 10 percent would be based and calculated. However, without knowing what future power costs will actually be, the potential impact on customer bills of the SSVEC proposal remains unclear.

Staff's recommendation that SSVEC be required to seek Commission approval for all adjustor rate increases remains unchanged.

Q. Does Staff agree with SSVEC's proposal that "[i]ncreases submitted to the Commission for approval . . . would become effective in 60 days unless the Commission took action."

A. No. Market conditions can change or new questions can arise concerning an application. Under such circumstances, a 60-day limit could potentially limit the Commission's ability to fully consider an increase before it automatically went into effect.

SSVEC'S PROPOSAL TO INCREASE THE THRESHOLD FOR UNDER-COLLECTION TO $4 MILLION

Q. Why has Staff recommended a threshold for under-collection?

A. Because, as an under-collection becomes larger, the increase to the WPCA adjustor rate required to resolve it is also likely to be larger, and this may result in rate shock for customers. Setting a threshold ensures that SSVEC will address the under-collection at a point where the increase to the WPCA rate required to resolve it will be smaller, and therefore limit the impact on customers.

Q. Does Staff agree with SSVEC's proposal that its under-collected threshold should be set at $4 million.

A. No. As discussed earlier in this testimony, an only slightly larger under-collected bank balance of $4.3 million resulted in increases to the adjustor rate that had a significant negative impact on customer bills. Staff also notes that SSVEC has expressed concern over timely cost recovery (discussed further herein). However, filing for an increase when the balance is at $2 million, as Staff is recommending, would produce more timely cost recovery for SSVEC than waiting until the balance is at $4 million.

Q. The Cooperative has expressed concern regarding the requirement for approval resulting in an inability to recover its costs in a timely manner. Please comment.

A. Staff notes that SSVEC need not wait until under-collections reach $2 million in order to file for an increase. Staff has recommended that SSVEC file an application to increase the bank balance when under-collections reach $2 million, *or when SSVEC reasonably projects that this threshold will be reached within six months and continue at or above the threshold for two or more consecutive months.* This latitude allows the Cooperative more timely recovery, in cases where the Cooperative can reasonably anticipate that its bank balance will exceed the upper threshold in the near future.

Q. What if sudden, unanticipated increases in the cost of power cause SSVEC to exceed its under-collected bank balance threshold?

A. Staff has recommended that SSVEC be required to file an application for approval of an increase to its adjustor rate whenever it exceeds the $2 million threshold on under-collections for its bank balance. Energy costs can be volatile and there could be sudden, unanticipated increases in the cost of power, resulting in SSVEC exceeding its threshold for under-collection in a relatively short period of time. In such a case, SSVEC would be filing for approval when its bank balance was already at $2 million, or more. However, while the approval process would slow cost recovery, the Cooperative's interest in timely cost recovery must be balanced against the Commission's obligation to limit rate shocks for SSVEC's customers.

Q. Staff has recommended that SSVEC be required to seek Commission approval for increases to the adjustor rate, but not for decreases. Would requiring Commission approval for only increases to the adjustor rate mean that over-collections could remain unresolved?

A. No. Staff has recommended that both upper and lower thresholds be imposed on the SSVEC bank balance. This would mean that, once the upper threshold is reached, SSVEC must make changes to the adjustor designed to return over-collections to ratepayers and reduced over-collections in a timely manner.

Q. Does this conclude your Surrebuttal Testimony?

A. Yes, it does.